CANADA

National Energy Board

Reasons for Decision

Esso Resources Canada Limited,
Shell Canada Limited, and
Gulf Canada Resources Limited

GH-10-88

August 1989

Gas Exports

National Energy Board

Reasons for Decision

In the Matter of

Esso Resources Canada Limited,
Shell Canada Limited,
and
Gulf Canada Resources Limited

Applications Pursuant to Part VI of the National Energy Board Act for Licences to Export Natural Gas

GH-10-88

August 1989

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Recital and Appearances

IN THE MATTER OF the National Energy Board Act and the Regulations made thereunder; and

IN THE MATTER OF applications by Esso Resources Canada Limited, Shell Canada Limited and Gulf Canada Resources Limited for licences under Part VI of the National Energy Board Act to export natural gas from the Mackenzie Delta.

HEARD at Ottawa, Ontario on 10, 11, 12, 13, 24, 25, 27 April and at Inuvik, N.W.T. on 18, 19, 20 April 1989.

BEFORE:

J.R. Jenkins	Presiding Member
J.-G. Fredette	Member
D.B. Smith	Member

APPEARANCES:

D.G. Hart, Q.C. D.G. Davies	Esso Resources Canada Limited; Shell Canada Limited; and Gulf Canada Resources Limited
T. Detlor	Beaufort Mackenzie Development Impact Zone Society
F. Bregha	Canadian Arctic Resources Committee
G.F. Paschen	Canadians for Responsible Northern Development
C.C. Buchanan	Canadian Petroleum Association
J. Allen	Council for Yukon Indians
G.W. Bell	Dene/Metis Negotiations Secretariat
P.C.P. Thompson, Q.C.	Industrial Gas Users Association
J.M. Evoy	Northwest Territories Federation of Labour
A.A. Fradsham	Alberta and Southern Gas Co. Ltd.
S.G. Trueman M.L. Pillman	Amoco Canada Petroleum Company Ltd.
R.J. Harrison T.G. Kane	ANR Pipeline Company
J.H. Farrell	Consumers' Gas Company Ltd., The
A. Wyche	Enron Gas Supply Company

J. Lutes B. Pierce	Foothills Pipe Lines (Yukon) Ltd. and Westcoast Energy Inc.
L.-C. Lalonde R. Lassonde J.S. Bulger	Gaz Métropolitain, inc.
J.D. Brett D.M.S. Geller	Greater Winnipeg Gas Company and ICG Utilities (Manitoba) Ltd.
D.K. Wilson J.H. Smellie	ICG Utilities (Ontario) Ltd.
L. Shafer	Interprovincial Pipe Line Company
T. Zuorro R. Gruben	Inuvialuit Regional Corporation
P. Olson	Murphy Oil Canada Limited
J.W. Harrison	Norcen Energy Resources Limited
B. Christie	Northwest Territories Power Corporation
J. Hopwood, Q.C.	NOVA Corporation of Alberta
W.M. Smith, Q.C. D.L. Huard	Pacific Interstate Transmission Company and Southern California Gas Company
L. Meyer	Pan-Alberta Gas Ltd.
C. Worthy	Petro-Canada Inc.
D.G. Gibson	Polar Gas Limited
N.J. Schultz C. Latimer	Tennessee Gas Pipeline Company
A.S. Taber, Jr. J.F. Weiler	Texas Eastern Transmission Corporation
S. Koskie	TransCanada PipeLines Limited
A. Mudryj, Q.C.	Union Gas Limited
E.B. McDougall	Washington Natural Gas Company
J. McNamara	Alberta Petroleum Marketing Commission
R. Milner	British Columbia Petroleum Corporation
J. Hill	Town of Inuvik
R. Hill	Inuvik Chamber of Commerce

W. Firth	Hamlet of Fort McPherson
A. Aviugana	Mackenzie Delta Beaufort Sea Regional Land Use Planning Commission
S. Freitag	Government of the Northwest Territories
V. Black W. Whicher	Minister of Energy for Ontario
G.A. Trudel J. Robitaille	Le Procureur général du Québec
L. Cabott R. Pokiak	Hamlet of Tuktoyaktuk
T. Detlor	City of Yellowknife
G. Michener, Q.C.	Government of the Yukon
E. Blondin	On her own Behalf
T. Butters	On his own Behalf
J. Churcher	On his own Behalf
R. Binne B. Archie	Porcupine Caribou Management Board
J. Cardinal	Inuvik Native Band
R. Bruce	Old Crow Indian Band
S.K. Fraser	Board Counsel

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Abbreviations

A&S	Alberta and Southern Gas Co. Ltd.
Act, the	National Energy Board Act
AGT	Algonquin Gas Transmission
AIP	Dene/Metis Agreement-in-Principle
ANGTS	Alaska Natural Gas Transmission System
ANR	ANR Pipeline Company
Applicants, the	Esso, Shell and Gulf
Board, the	National Energy Board
CARC	Canadian Arctic Resources Committee
CIG	Channel Industries Gas Company
COGLA	Canadian Oil & Gas Lands Administration
Consumers	Consumers' Gas Company Ltd.,The
CRND	Canadians for Responsible Northern Development
CYI	Council for Yukon Indians
Dene/Metis	The Dene/Metis Negotiations Secretariat or The Dene Nation and The Metis Association of the Northwest Territories
DIZ Society	Beaufort Mackenzie Development Impact Zone Society
DSTs	drill stem tests
EGS	Enron Gas Supply Company
EIA	export impact assessment
Enron	Enron Corp.
Esso	Esso Resources Canada Limited
ETNG	East Tennessee Natural Gas Co.
Foothills	Foothills Pipe Lines (Yukon) Ltd.
GMi	Gaz Métropolitain, inc.
GNWT	Government of the Northwest Territories
Greater Winnipeg	Greater Winnipeg Gas Company
GRI	Gas Research Institute
GSC	Geological Survey of Canada

Gulf	Gulf Canada Resources Limited
Hearing, the	GH-10-88 Hearing
ICG	ICG Utilities (Ontario) Ltd.
IGUA	Industrial Gas Users Association
IRC	Inuvialuit Regional Corporation
LDC	local distribution companies
LNG	liquified natural gas
MGT	Midwestern Gas Transmission Company
NEB	National Energy Board
NOVA	NOVA Corporation of Alberta
Ontario	Minister of Energy for Ontario
October 1986 Report	Canadian Energy Supply and Demand, 1985-2005, October 1986
PG&E	Pacific Gas and Electric Company
PITCO	Pacific Interstate Transmission Company
Quebec	Le Procureur général du Québec
Shell	Shell Canada Limited
September 1988 Report	Canadian Energy Supply and Demand, 1987-2005, September 1988
SoCal	Southern California Gas Company
SOCL	social opportunity cost of labour
TCPL	TransCanada PipeLines Limited
TEGPL	Texas Eastern Gas Pipeline Company
Tenneco	Tenneco Gas
Tennessee	Tennessee Gas Pipeline Company
Texas Eastern	Texas Eastern Transmission Corporation
Tuktoyaktuk	Hamlet of Tuktoyaktuk
Union	Union Gas Limited
WCSB	Western Canada Sedimentary Basin
WGML	Western Gas Marketing Limited
YTG	Government of the Yukon Territory

Units

$10^3m^3/d$	thousands of cubic metres per day
10^6m^3	million cubic metres
$10^6m^3/d$	millions of cubic metres per day
10^9m^3	billion cubic metres
bcf	billion cubic feet
EJ	exajoule = 10^{18} joules
GJ	gigajoule = 10^9 joules
hp	horsepower
km	kilometres
m	metres
mi	miles
MMbtu	million British thermal units
MMcfd	millions of cubic feet per day
MW	megawatt = 10^6 watts
PJ	petajoule = 10^{15} joules
Tbtu	trillion British thermal units
Tcf	trillion cubic feet

Conversion Factors

1 cubic metre of natural gas (101.325 kilopascals and 15°C)	=	35.301 cubic feet (14.73 psia and 60°F)
1 cubic metre of condensate (equilibrium pressure and 15°C)	=	6.29 barrels of condensate (equilibrium pressure and 60°F)
1 gigajoule (GJ)	=	approx. 0.95 million Btu, or 0.95 thousand cubic feet of natural gas at 1000 Btu/cf
1 petajoule (PJ)	=	approx. 0.95 trillion Btu, or 0.95 billion cubic feet of natural gas at 1000 Btu/cf
1 exajoule (EJ)	=	approx. 950 trillion Btu, or 0.95 trillion cubic feet of natural gas at 1000 Btu/cf
1 metre	=	3.281 feet
1 kilometre	=	0.621 miles
1 km^2	=	0.386 square miles
1 MW	=	1341 horsepower

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Chapter 1

Introduction

1.1 The Applications

By applications dated 21 September 1988, Esso Resources Canada Limited ("Esso") and Shell Canada Limited ("Shell") applied to the National Energy Board ("the Board" or "NEB") for licences, under Part VI of the *National Energy Board Act* (the "Act"), to export natural gas from the Mackenzie Delta to the United States. Similarly, by an application dated 8 February 1989, Gulf Canada Resources Limited ("Gulf") applied to the Board for a licence, under Part VI of the Act, to export natural gas from the Mackenzie Delta to the United States.

Esso, Shell and Gulf (collectively to be called the ("Applicants") requested licences for the period commencing 1 November 1996 and ending on the 31 October 2000, provided that if the exports commence by 31 October 2000, the licence term would extend for a period of 20 years from November 1 of the year in which the exports commenced.

Esso proposes to export 144 billion cubic metres (5.1 trillion cubic feet), Shell proposes to export 25 billion cubic metres (0.9 trillion cubic feet) and Gulf proposes to export 91 billion cubic metres (3.2 trillion cubic feet) of natural gas from reserves in the Mackenzie Delta.

These are the first applications the Board has dealt with for the export of natural gas from the Mackenzie Delta and as such are the first export applications dealing with major frontier development.

The Applicants have entered into Precedent Agreements with several buyers in the United States who have expressed an intention to enter into long-term contracts by 30 June 1990 for the purchase of a share of the gas. Some Canadian customers have had discussions with the Applicants regarding the purchase of Delta gas.

New pipeline facilities would have to be built to connect Mackenzie Delta reserves to existing systems in southern Canada. The Applicants stated that, if an independent pipeline company were unable to offer satisfactory and competitive service in a timely manner, one of them would be prepared to play a lead role in developing an acceptable system.

The Applicants stressed that to support such a transportation facility, it would be necessary to operate a large volume system at initial full capacity. Introduction of such a volume directly and physically into the domestic market, in the Applicants' view, would result in the displacement or the disruption of supplies from the conventional producing areas of western Canada. According to the Applicants, direct access to the much larger U.S. market is, therefore, essential for the development of Delta gas and associated pipeline facilities.

The Applicants contended that securing export licences is a necessary first step in the lengthy process of obtaining other regulatory approvals, finalizing marketing and transportation arrangements and actually producing the gas.

Interventions were received from some 60 interested parties including companies, associations, individuals and provincial governments. Many of these parties participated in the public hearing which was held in Ottawa from 10 to 13 April 1989, in Inuvik from 18 to 20 April 1989, and again in Ottawa on 24, 25 and 27 April 1989. The Board also received several letters of comment.

1.2 The Market-Based Procedure

Section 118 of the Act requires the Board, in considering an application for a licence to export gas, to have regard to all considerations that appear to it to be relevant. In particular, the Board must satisfy itself that the quantity of gas to be exported does not exceed the surplus remaining

after due allowance has been made for reasonably foreseeable Canadian requirements, taking account of trends in discovery.

In complying with the requirements of Section 118 of the Act, the Board uses its Market-Based Procedure. This procedure includes consideration of complaints, if any, under the complaints procedure; an export impact assessment ("EIA"); and other factors which the Board considers relevant in its determination of the public interest including net benefits to Canada, the Applicants' supply as it relates to reserves and productive capacity, upstream and downstream transportation arrangements and markets.

The *complaints procedure* provides an opportunity for Canadian gas-users to object to an export proposal on the grounds that they have not been able to contract additional gas supplies under similar terms and conditions, including price, to those in the export licence application.

Several views were put forward regarding the complaints procedure and whether or not it could work in the unique circumstances of these applications. This is discussed in more detail in Chapter 5.

The purpose of the *export impact assessment* is to allow the Board to determine whether a proposed export is likely to cause Canadians major adjustment difficulties in meeting their energy requirements at fair market prices.

The Board considers several *matters of public interest* to be relevant in examining these applications, including:

- specific Northern issues such as the Dene-Metis land claim and benefits to Northerners;
- the Applicants' reserves and productive capacity, including the potential for additional gas supply in the Mackenzie Delta-Beaufort Sea region and the supply costs of northern gas;
- the anticipated transportation and other costs related to at least one possible pipeline facility for movement of the gas;
- the nature of the markets and associated gas sales arrangements including local supply for Northerners; and
- the net benefits to Canada from the sale of the proposed exports.

1.3 Canadian Arctic Resources Committee Motion

Canadian Arctic Resources Committee ("CARC") filed a motion which was dealt with at the outset of the hearing requesting that the Board not make a determination about whether or not the proposed exports are in the public interest. CARC suggested that the Board could not make an informed decision regarding whether the applications before it were in the public interest without hearing detailed evidence on pipeline routing, design and costs. As well, CARC believed that granting export licences now would be inconsistent with the Board's surplus determination policy.

The Board denied CARC's Motion because it believed that the request went to the very question which the Board would have to determine at the end of the hearing. The Board stated that a determination as to whether the proposed exports were in the public interest could only be made after hearing and testing the Applicants' case and the evidence and submissions of Intervenors.

Chapter 2

Gas Supply

2.1 Established Reserves

The Applicants provided estimates of reserves for those fields from which each intends to produce natural gas for its proposed export. The Board has analyzed each Applicant's supply data and prepared its own estimate of established gas reserves. Table 2-1 compares the Board's reserves estimates with those of the Applicants.

The Board's analysis involved a detailed review of the available geological and engineering data for both the Applicants' fields and the Delta region. Extensive reliance was placed upon the Applicants' submitted geophysical data and interpretations, as well as analogies to other known areas such as the American Gulf coast. Gas reserves were identified as associated, non-associated or solution.

Probability curves were used to estimate the established gas reserves. A typical probability curve represents all possible reserves estimates, because of the range of all input variables, including area, pay thickness, porosity, gas saturation, recovery factor, gas deviation factor, temperature, pressure and surface loss. A reserves estimate in the low probability range (10 percent) has more uncertainty and higher risk, and thus is more speculative than a reserves estimate in the high probability range (90 percent). The low probability reserves estimate is usually much larger than the high probability reserves estimate. The Board adopts the industry practice of using the median or most likely probability. In most cases, the 50 percent probability reserves estimate was adopted.

Table 2-1

Comparison of Estimates of Established Reserves
March, 1989

Billions of Cubic Metres (Bcf)

	Non-associated[1]		Associated[2]		Solution[3]		Total	
Esso	139.8	(4,935)	4.7	(166)	0.0	(0)	144.5	(5,101)
Gulf	93.0	(3,283)	18.3	(646)	8.0	(282)	119.3	(4,211)
Shell	29.1	(1,027)	0.0	(0)	0.0	(0)	29.1	(1,027)
Applicants' Total	261.9	(9,245)	23.0	(812)	8.0	(282)	292.9	(10,339)
NEB Total	263.2	(9,291)	22.4	(791)	10.5	(371)	296.1	(10,453)

1 Non-associated gas is that gas not in contact with crude oil in the reservoir.
2 Associated gas is that gas, commonly known as gas cap gas, which overlies and is in contact with crude oil in the reservoir.
3 Solution gas is that gas in solution with crude oil in the reservoir at original reservoir conditions and which is normally produced with the crude oil.

The larger, well controlled and well defined gas fields exhibit less variance between the high and low probability estimates than do the small, less well defined gas fields. Likewise, for the large gas fields there is excellent agreement between the Applicants' and the Board's estimates of established gas reserves while there are large differences in gas reserves estimates for some of the small sparsely controlled gas fields. Nevertheless these differences are not numerically large and are often compensating. In total, despite the inherent uncertainties in estimating established reserves in multi-zone, faulted reservoirs such as those in the Delta, there is excellent agreement between the Applicants' and the Board's estimates as shown in Table 2-1 and Tables 2-2 through 2-4.

Esso

Esso's reserves estimate of 144.5 10^9m^3 (5.1 Tcf) includes both associated and non-associated gas reserves, but does not include solution gas reserves. The associated gas reserves represent about 3.3 percent of Esso's total supply. In developing production forecasts, Esso assumed that economically producible oil reserves would have been depleted before production of the associated gas cap would begin. The Board considers this to be a fair assumption. However, in the Board's opinion, the associated gas reserves in the Arnak, Hansen and Itiyok Fields are too small to be deemed established, and only the non-associated gas reserves in those fields are included in Tables 2-1 and 2-2. The differences in the gas reserves estimates for the Arnak and Hansen fields are due mainly to the area factor; as well, the areas determined by Esso for some of the Kadluk pools seem excessive.

Esso used gas recovery factors ranging from 75 percent for relatively thin gas sands overlying water, to 89 percent for thick sands with no acquifers. Reservoirs with down-dip water zones were assigned recovery factors between these two values, depending on the distance from and the quality of the acquifer.

Table 2-2

Comparison of Estimates of Established Reserves - Esso
March, 1989

Billions of Cubic Metres (Bcf)

Field	Gas Type	Esso		NEB	
Arnak	non-associated	0.6	(21)	0.5	(18)
	associated	0.8	(28)	0.0	(0)
Hansen	non-associated	0.9	(32)	6.4	(226)
	associated	0.7	(25)	0.0	(0)
Issungnak	non-associated	29.0	(1,024)	27.8	(981)
	associated	2.7	(95)	3.8	(134)
Itiyok	non-associated	2.6	(92)	4.1	(145)
	associated	0.5	(18)	0.0	(0)
Kadluk	non-associated	6.6	(233)	5.0	(177)
Mallik	non-associated	2.8	(99)	1.4	(49)
Netserk	non-associated	3.9	(138)	2.3	(81)
Taglu	non-associated	86.5	(3,053)	86.5	(3,053)
Tuk Cret.	non-associated	6.8	(240)	6.4	(226)
Total	non-associated	139.8	(4,935)	140.4	(4,956)
Total	all types	144.5	(5,100)	144.2	(5,090)

Note: Figures may not add due to rounding.

Gulf

Gulf estimates that the three fields in its application contain 119.3 10^9m^3 (4.2 Tcf) of established gas reserves (Table 2-3). This volume includes associated, non-associated and solution gas reserves. Gulf has applied to export only its non-associated gas reserves which it estimates at 93.0 10^9m^3 (3.3 Tcf). Gulf used a recovery factor of 80 percent for all pools in its application. This estimate may be slightly conservative.

In the Ya Ya North and Ya Ya South fields, Gulf used water saturations between 70 and 80 percent for some reservoirs with gas flow rates as high as 158 10^3m^3/d (5.6 MMcfd) with no water recovery. These anomalously high apparent water saturations may be due to the shaly nature of the particular reservoirs, and are likely the reason for the conservative gas reserves estimates.

Shell

Shell included only non-associated gas reserves in the Niglintgak and Kumak fields in its application; these reserves, totalling some 29.1 10^9m^3 (1.0 Tcf), are shown in Table 2-4.

Shell used a recovery factor of 85 percent for all but the "G" sand in the Niglintgak field even though its studies indicated some reservoirs may have recovery factors as high as 90 percent. A

Table 2-3

Comparison of Estimates of Established Reserves - Gulf
March, 1989

Billions of Cubic Metres (Bcf)

Field	Gas Type	Gulf	NEB
Amauligak	non-associated	37.0 (1,306)	37.5 (1,324)
	associated	18.3 (646)	18.6 (657)
	solution	8.0 (282)	10.5 (371)
Parsons	non-associated	51.7 (1,825)	51.0 (1,800)
Ya Ya North	non-associated	1.6 (56)	2.1 (74)
Ya Ya South	non-associated	2.7 (95)	3.3 (116)
Total	non-associated	93.0 (3,283)	93.9 (3,315)
Total	all types	119.3 (4,211)	123.0 (4,342)

Table 2-4

Comparison of Estimates of Established Reserves - Shell
March, 1989

Billions of Cubic Metres (Bcf)

Field	Gas Type	Shell	NEB
Niglintgak	non-associated	27.5 (971)	27.5 (971)
Kumak	non-associated	1.6 (56)	1.4 (49)
Total		29.1 (1,027)	28.9 (1,020)

recovery factor of 75 percent was assumed for the "G" sand because the thin gas column appears to be underlain by water.

Summary

A comparison of the reserves estimates, presented in Tables 2-2 to 2-4, shows that each Applicant has sufficient reserves to satisfy its export request.

2.2 Possible and Potential Reserves

The Applicants each carry some possible reserves on their controlled lands in the Mackenzie-Beaufort region, although none were included in their proposed export volumes. Gulf and Shell stated that an estimate of their possible reserves would equate to a few percent of their total estimated established reserves and stated that they also expect some appreciation of reserves on their lands. Esso, however, has identified both possible and potential reserves totalling some 120 10^9m^3 (4.2 Tcf) in its fields; it estimates that, at a reasonable risk level, it expects 57 10^9m^3 (2.0 Tcf) could be added to its fields.

At this time each of the Applicants is both carrying out and planning exploration and drilling programs on the lands they hold in the region. They noted that after 1991, with the expiry of existing land rights, future exploration activity would be in part dependent upon what mechanisms exist for land sales.

The Applicants concurred with estimates, published by both the Canadian Oil & Gas Lands Administration ("COGLA") and the Geological Survey of Canada ("GSC"), of 1 600 10^9m^3 (56.5 Tcf) of undiscovered potential for the Mackenzie-Beaufort region. Table 2-5 is a summary of the GSC estimates. The data in Table 2-5 are based on the assumption that 1 630 to 2 070 10^9m^3 (57.5 to 73.1 Tcf) of gas may exist in the Mackenzie-Beaufort region at a 75 to 25 percent probability range with a mean expectation of some 1 926 10^9m^3 (68.0 Tcf) in the various areas of the region.

The Board believes that the most likely source of additional reserves in the near term will be the "Onshore & Shallow Offshore" and the "Offshore Delta" areas of the region. Although the "West Beaufort" and the "Deep Water & Other" areas are the least explored and have numerous untested structures, severe conditions, such as water depths to 100 metres (330 feet) and winter ice, may make it impossible to produce reserves economically in those areas. Nevertheless, even without the potential reserves from these two areas, there would still remain 1 038 10^9m^3 (36.6 Tcf) of discovered and undiscovered gas resources in the remaining areas.

The construction of a pipeline into this region would undoubtedly stimulate exploration and development of the undiscovered gas potential. Even a conservative realization of undiscovered potential would keep gas flowing at the proposed rates for many years beyond the export period.

Table 2-5

Mackenzie Delta - Beaufort Sea
Natural Gas Resources at the Mean Expectation Level[1]

Billions of Cubic Metres (Tcf)

Area	Discovered		Undiscovered	
Onshore & Shallow Offshore	211.9	(7.48)	409.6	(14.46)
Offshore Delta	93.2	(3.29)	322.9	(11.40)
West Beaufort	0.0	(0.0)	354.1	(12.50)
Deep Water & Other	24.9	(0.88)	501.4	(17.70)
Totals	330.0	(11.65)	1588.0	(56.06)

1 GSC open file 1926, *Petroleum Resources of the Mackenzie Delta - Beaufort Sea*, dated 1988.

2.3 Productive Capacity

Each Applicant provided forecasts of expected productive capacity from their lands in the Mackenzie-Beaufort region. By analyzing drill stem tests ("DSTs") the Applicants were able to assign suitable production rates to each field and determine a reasonable tie-in schedule to satisfy overall requirements.

The Board prepared projections of productive capacity from the established reserves listed in Tables 2-2 to 2-4 of Chapter 2.1 using both the basic reservoir and test data supplied by the Applicants and the Applicants' proposed tie-in schedules.

Table 2-6 is a comparison of the Applicants' and the Board's overall productive capacity projections with comparisons for each Applicant found in Appendix Tables A-1 to A-3.

Figure 2-1 compares the total proposed annual export levels with both the Applicants' and the NEB's projections of overall productive capacity.

Generally the Board's estimates of productive capacity fell short of the Applicants' estimates, particularly those of Gulf and Shell. The Board believes this is due primarily to the limited nature of the flow data available. Due to the cost of carrying out production tests in these remote areas, most test information was derived from DST data which tend not to give an accurate picture of well capability. The Board anticipates that before production commences more extensive flow testing would occur in these fields. Supply would, of course, be re-assessed in any facility hearing for the transportation of the gas.

Most of the gas reserves supporting the Applicants' requests are contained in very good to excellent reservoirs which generally exhibit productive capacities much higher than a normal 20 year contract rate dictates. Zones have been tested at rates up to 1 400 $10^3m^3/d$ (49.4 MMcfd) with calculated absolute open flows up to 20 388 $10^3m^3/d$ (720 MMcfd).

Considering the production rates assumed by the Applicants, the size of the reserves, the nature of

FIGURE 2-1

COMPARISIONS OF ESTIMATES OF PRODUCTIVE CAPACITY

FOR THE MACKENZIE-BEAUFORT REGION

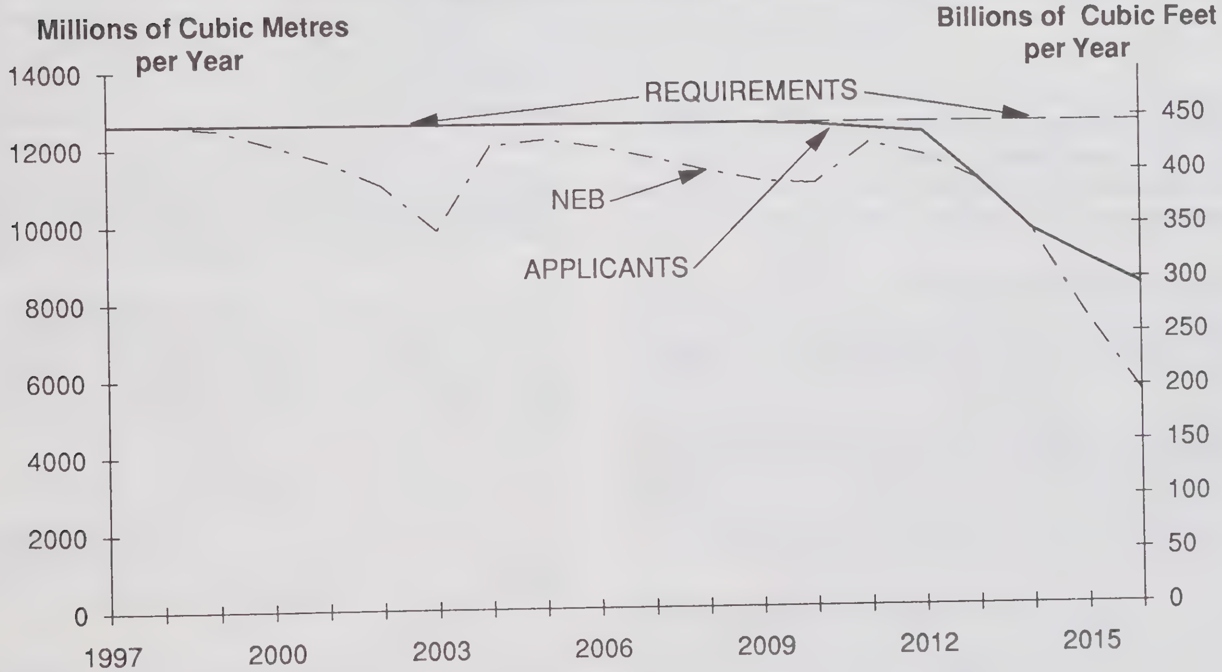

Table 2-6

Comparison of Estimates of Productive Capacity for the Mackenzie-Beaufort Region

Millions of Cubic Metres (Bcf)

Year	Applicants		NEB	
1997	12 619	(445)	12 619	(445)
1998	12 619	(445)	12 619	(445)
1999	12 619	(445)	12 489	(441)
2000	12 619	(445)	12 090	(427)
2001	12 619	(445)	11 671	(412)
2002	12 619	(445)	11 062	(390)
2003	12 619	(445)	9 877	(349)
2004	12 619	(445)	12 064	(426)
2005	12 619	(445)	12 207	(431)
2006	12 619	(445)	12 023	(424)
2007	12 619	(445)	11 722	(414)
2008	12 619	(445)	11 392	(402)
2009	12 619	(445)	11 100	(392)
2010	12 557	(443)	11 020	(389)
2011	12 444	(439)	12 067	(426)
2012	12 351	(436)	11 742	(415)
2013	11 137	(393)	11 114	(392)
2014	9 807	(346)	9 787	(345)
2015	9 052	(320)	7 505	(265)
2016	8 355	(295)	5 520	(195)

the reservoirs and the substantial potential for reserves additions in the area, the Board believes that the Applicants' projected rates can be achieved, and the Applicants will have sufficient supply to meet their export requirements.

2.4 Natural Gas Costs

The export applications provided the first opportunity since the Mackenzie Valley Hearing[1] to examine, in the context of a formal hearing, the cost of natural gas from the Mackenzie Delta and the Beaufort Sea. The Applicants' gas cost information was used to determine gas supply costs for the benefit-cost analysis of the export applications.

The Applicants submitted estimates of production costs which include costs of development wells, gathering lines, processing plants and later in the project term, the construction of offshore islands. Estimated unit production costs and the first year of production for each Applicant's pools are shown in Table 2-7. The unit costs for Esso and Shell pools are as submitted; Gulf unit costs are Board estimates based on data submitted by Gulf. On a volume weighted basis, unit production costs average $1.00/GJ ($1.05/MMbtu). Estimated costs for Esso were slightly below this amount; Gulf costs were somewhat higher. All costs incurred prior to 1989 are sunk costs and are thus not included in these estimates.

The Applicants also submitted cost estimates for two new pipeline systems to transport the gas to Caroline, Alberta, and from Caroline to the U.S. border. Unit transportation costs, which account for pipeline capital and operating costs, were $1.33/GJ ($1.40/MMbtu) of delivered sales gas from the Delta to Caroline and $0.24/GJ ($0.25/MMbtu) from Caroline to the U.S. border. This is the uniform charge in 1988 dollars needed to provide for return of capital and operating costs and a real return to capital of eight percent.

The Applicants' estimated weighted direct costs for natural gas from the Mackenzie Delta/Beaufort Sea region delivered at Caroline, Alberta, are the sum of unit production and transportation costs, or $2.33/GJ ($2.46/MMbtu).

Although the unit costs as calculated above are a convenient way to summarize cost information, the time profile of actual capital and operating expenditures is required for a benefit-cost analysis. The financial viability of a project is influenced by capital costs, the greatest portion of which is incurred at the front end of a project, and by pipeline tolls which, on a cost of service basis using the conventional straight line depreciation method, are higher earlier in the life of a pipeline. The Applicants estimated a cost of service toll for a new pipeline from the Delta to Caroline in 1988 dollars to be $2.28/GJ ($2.40/MMbtu) in 1997, $1.97/GJ ($2.08/MMbtu) in 1999, and $1.74/GJ ($1.84/MMbtu) in 2001.

The applied-for gas exports are expected to be produced from 260 10^9m^3 (9.18 Tcf) of discovered reserves. The Applicants submitted that additional gas likely would be discovered and produced in the

1 National Energy Board, Reasons for Decision Northern Pipelines, June 1977.

Table 2-7

Unit Production Costs and Probable First Year of Production

$1988/gigajoule ($1988/MMbtu)

Pool	Unit Production Costs[1]		First Year of Production
Esso			
Taglu	0.54	(0.57)	1997
Tuk	1.41	(1.49)	2004
Mallik	1.66	(1.75)	2005
Hansen	3.20	(3.37)	2005
Issungnak	1.45	(1.53)	2006
Netserk	4.24	(4.47)	2009
Kadluk	2.69	(2.84)	2010
Itiyok	5.97	(6.30)	2012
Arnak	8.99	(9.48)	2013
Shell			
Niglintgak	1.02	(1.08)	1997
Gulf[2]			
Parsons Lake	1.03	(1.09)	1997
East Amauligak	1.17	(1.23)	2004
Ya Ya	1.69	(1.78)	2007

1 Unit production costs spread development, capital and lifting costs over the estimated production period of each pool at a real discount rate of eight percent per year. Taglu, Niglintgak and Parsons Lake account for 57 percent of the total gas volumes. Reserves estimates for each of these pools are provided in Tables 2-2 to 2-4.

2 Estimated by the Board from data submitted by Gulf.

area once a transportation system were in place. As noted, this view was based on the GSC's assessment of the area's technical potential.

The Applicants estimated finding costs of future discoveries to be $60 million for onshore discoveries in the 100-300 petajoule (95-285 Tbtu) range. Development and production costs for these new discoveries would be comparable to costs for similarly sized fields included in the applications.

Views of the Board

The Board finds the development, production and exploration cost estimates submitted by the Applicants to be reasonable. The Board also agrees that additional discoveries in the Mackenzie Delta and Beaufort Sea are likely if gas from the discoveries can be marketed.

For the benefit-cost analysis, the Board requires estimates of the cost of natural gas from different producing regions, and estimates of volumes that could be produced at various costs.

To arrive at the volumes for the benefit-cost analysis, the GSC's estimates of technical potential must be reduced by an estimate of uneconomic volumes. In the Board's opinion, only gas from discoveries in the onshore/shallow offshore areas of the Mackenzie Delta and in the offshore Delta is likely to be developed, given the Applicants' range of gas price projections or those published in the Board staff's September 1988 Report *Canadian Energy Supply*

and Demand, 1987-2005 ("September 1988 Report"). The GSC's estimates of potential for these regions must be reduced further to reflect the unattractive full-cycle economics of small discoveries.

The Applicants' estimated finding costs for new gas are somewhat higher than those for past discoveries. The Board examined the record of discoveries and associated costs in the onshore and offshore areas and concluded that because of the immature stage of exploration it is difficult to identify a trend in finding costs. However, based on the experience to date, the Applicants' estimates of the cost of new discoveries in the onshore/shallow offshore areas of the Mackenzie Delta appear to be within a plausible range.

The Board also estimated the cost of new discoveries in the offshore Beaufort, by increasing the Applicants' finding costs from $60 to $90 million for discoveries in the 100-300 petajoule (95-285 Tbtu) range to reflect the higher costs of offshore drilling. Development and production costs in the range defined by Esso's Issungnak and Kadluk fields were assumed to be representative of the costs of developing similar sized fields in the future.

Development of only the larger pools is expected in the Applicants' low price case. In the Applicants' high price case, all onshore pools, and offshore pools as small as Esso's Kadluk discovery appear viable. Somewhat higher gas prices were projected in the September 1988 Report. Higher gas prices could make smaller pools more attractive to develop. However, the Board notes that the cost of finding and producing gas increases as pool size decreases. In the Board's opinion, onshore discoveries smaller than 40 petajoules (38 Tbtu), and offshore discoveries smaller than 150 petajoules (143 Tbtu), are unlikely to be developed for production.

The Board's estimates of costs and potential supply of gas from the onshore/shallow offshore areas of the Delta, and the offshore Delta for the benefit-cost analysis are shown in Table 2-8. The cost of gas from new discoveries (undiscovered potential) includes finding, development and production costs, and only the operating cost of the pipeline from the Mackenzie Delta. The pipeline's capital costs are spread over the Applicants' applied-for export volumes and therefore are not included as a direct cost for new discoveries.

Table 2-8

Gas Supply and Direct Cost Estimates

	Supply Petajoules (Tbtu)	**Direct Costs**[1] $1988/gigajoule ($1988/MMbtu)		
Discount rate		6%	8%	10%
Applicants' Supply[2]	9 187 (8,728)	2.08 (2.19)	2.33 (2.46)	2.61 (2.75)
Estimated Undiscovered Economic Potential[3]				
Onshore and Shallow Offshore	12 367 (11,749)	2.35 (2.48)	2.60 (2.74)	2.76 (2.91)
Offshore Delta	10 526 (10,000)	2.82 (2.97)	3.12 (3.29)	3.42 (3.61)

1 Estimated costs per gigajoule of sales gas delivered to Caroline, Alberta; the cost of fuel gas is included in the cost estimates; reserves are reduced by estimated fuel volumes to Caroline.
2 Excludes associated and solution gas from Amauligak.
3 Established reserves not dedicated to the export project are included in the undiscovered potential.

Markets and Gas Sales Arrangements

The Applicants submitted that the applications to export Mackenzie Delta gas to the United States are a culmination of many years of activity and investment in the Delta area. The Applicants stressed that applications for licences are the first step in the lengthy process before gas begins to flow to market and securing the export licences would enhance the Applicants' opportunity to negotiate with U.S. buyers. In this Chapter, the general U.S. market background is discussed followed by a discussion of the evidence on potential individual buyers' markets and the contracting process.

3.1 U.S. Markets

The Applicants submitted that by the mid to late 1990s, the demand for natural gas in the United States will certainly exceed the available American supply, and it was for this reason that major companies such as Enron Gas Supply Company ("EGS"), Texas Eastern Transmission Corporation ("Texas Eastern"), Pacific Interstate Transmission Company ("PITCO") and Tennessee Gas Pipeline Company ("Tennessee") have entered into Precedent Agreements expressing their interest to purchase Delta gas.

While both Alberta and Southern Gas Co. Ltd. ("A&S") and ANR Pipeline Company ("ANR") have entered into Precedent Agreements with the Applicants, they were not active participants at the hearing and did not specify the volumes they intended to contract.

The Applicants submitted that in the present market environment it would be difficult to secure firm purchase contracts with U.S. buyers without having an export licence. The Applicants also submitted that the export market was essential to the development of Mackenzie Delta gas. The Applicants cited the large expenditures to be made by themselves and others, totalling $4.8 billion for field facilities and $6.1 billion for pipelines, and testified that, for the project to be economic, the facilities had to be operated at essentially full capacity from the outset.

In support of their applications, the Applicants submitted a forecast of U.S. natural gas supply and demand to the year 2020. The forecast adopted the 1988 Gas Research Institute ("GRI") baseline projections which run to the year 2010. DataMetrics Limited extrapolated the forecast to the year 2020. In the GRI study, United States demand is projected to grow from 18.99 EJ (18,006 Tbtu) in 1988 to 21.06 EJ (19,970 Tbtu) in 2020. Production from the Lower 48 states, estimated at 17.61 EJ (16,701 Tbtu) in 1988, is projected to peak at 17.83 EJ (16,906 Tbtu) in the year 2000 and decline thereafter to 16.26 EJ (15,421 Tbtu) by 2020. Net Canadian imports are expected to range from a low of 1 261 PJ (1,196 Tbtu) in 1988 to a high of 2 026 PJ (1,921 Tbtu) in 2020. The remainder of United States demand is expected to be satisfied by LNG imports, Mexican imports, and gas from Alaska and other unspecified sources.

The underlying assumptions of this GRI forecast were that world oil prices would be between $20 U.S. per barrel and $30 U.S. per barrel (1987 dollars) to the year 2000 after which they would exceed $30 U.S. per barrel. In terms of the basic structural aspects of energy demand, GRI assumed declines in energy intensity reflecting continued improvements in energy efficiency and output shifts away from energy intensive activity. GRI also assumed that drilling costs and activity were unlikely to return to rates prior to 1981 but would be held down by gas prices in competition with residual fuel oil.

On a regional basis, the GRI study indicated that the supply to the Northeast region would have an increasing reliance on LNG imports and Alaskan gas commencing between 2005 and 2010.

The Southern region showed sustained erosion of the reserves to serve other areas in the U.S. After 2005, the production in the South would decline,

and its ability to supply other regions would drop to the point where the South would require 211 petajoules (200 Tbtu) of imports from Mexico and offshore LNG supplies.

The West Coast showed a gradual increase in imports to 2005 after which imports were largely displaced by Alaskan gas. However, a witness for the study entitled "Assessment of California Natural Gas Demand and Supply: 1987-2017", prepared for one of Applicants' buyers, testified that the Alaskan gas "would not be coming on-line during the period, or would be going via an alternative route to non-U.S. sources... The most probable market for Alaskan gas is the Far East".

The Great Lakes region showed a progressively increased level of Canadian imports throughout the projected period.

The projected supply to the Midwest would be from the Rocky Mountain Forerange where there is considerable productive capacity not yet matched by pipeline facilities.

To date, the Applicants have entered into Precedent Agreements with a number of U.S. buyers (Table 3-1).

The evidence indicated that the Applicants had received interest in 17.0 to 25.5 10^6m^3 (600 to 900 MMcfd), approximately 50 to 75 percent of the 34.0 10^6m^3 (1,200 MMcfd) applied-for export volumes. For the balance, 17.0 to 8.5 10^6m^3 (600 to 300 MMcfd), the Applicants will pursue further negotiations with American and Canadian customers until all of the applied-for volumes are signed up.

Each of the potential U.S. Buyers, whose markets are described below, indicated a strong interest for Canadian gas, for a 20-year term with a uniform volume throughout the term. Some buyers, however, were more flexible than others regarding the possible start-up date, the length of the term, and the volume levels throughout the term.

EGS is a wholly owned subsidiary of Enron Corp. ("Enron") formed to acquire supplies of gas from diverse sources to satisfy the existing and projected needs of Enron, an amalgamation of Internorth Inc. and Houston Natural Gas. Enron is composed of four major pipeline companies: Northern Natural Gas, Houston Pipe Line, Florida Gas Transmission and Transwestern Pipeline. Enron is also joint owner and operator of the Northern Border Pipeline. The Enron system serves the fastest growing markets in the United States, namely Texas, California, Florida and the upper Midwest. Also, it offers direct access to virtually all gas supply basins in the U.S. as well as direct access to Canadian and Mexican supplies. Unlike other pipeline systems, Enron has chosen to retain and expand its merchant function rather than become solely a transporter of natural gas.

Enron stated that its level of Canadian gas supply was probably in the range of 5 to 8 percent of its

Table 3-1

Volumes Expected to be Taken Pursuant to Precedent Agreements

Applicants	U.S. Buyers	$10^6m^3/d$	(MMcfd)
Esso/Shell/Gulf	EGS	5.7 to 8.5	(200 to 300)
Esso/Shell/Gulf	PITCO	2.8 to 8.5	(100 to 300)
Esso	Texas Eastern	4.2	(150)
Gulf	Tennessee	4.2	(150)
Esso	A&S	Unknown	
Esso	ANR	Unknown	
Total		17.0 to 25.5	(600 to 900)

Note: The Precedent Agreements indicate an intention to purchase a portion of the volumes available for sale.

total supply. However, Canadian gas is really only available to the Northern Natural Gas pipeline system where Enron estimated it to be some 15 to 18 percent of system supply.

PITCO is a subsidiary of Los Angeles-based Pacific Enterprises whose primary activity is the importation of natural gas from Canada and Southeast U.S. to Southern California for its affiliate and sole customer Southern California Gas Company ("SoCal"). SoCal is the largest U.S. public utility, serving the city of Los Angeles as well as 531 other communities. Presently, Canadian gas makes up 100 percent of PITCO's supply.

A division of Texas Eastern, Texas Eastern Gas Pipeline Company ("TEGPL"), operates an interstate natural gas pipeline which extends from the Texas/Mexico border to the New Jersey/New York area. Its major service area is the Mid-Atlantic where it sells or transports gas to local distribution companies as well as to other interstate pipelines. TEGPL's major customer is Algonquin Gas Transmission ("AGT"), a wholly-owned subsidiary, which serves the New England states. Texas Eastern believes that there will be continued growth in the Northeast markets for natural gas, primarily to meet electric generation and firm cogeneration loads.

In 1987, TEGPL's total throughput was approximately 29 688 10^6m^3 (1,048 Bcf), of which approximately 2 percent was supplied from Canada.

Tennessee is one of four major pipeline companies administered by Tenneco Gas ("Tenneco"). The other companies are Midwestern Gas Transmission Company ("MGT"), East Tennessee Natural Gas Co. ("ETNG") and Channel Industries Gas Company ("CIG"). Tenneco's market area stretches north from the Gulf Coast to New York, Pennsylvania, West Virginia and the New England states.

Presently, Tenneco imports Canadian gas at Niagara Falls, Ontario and Emerson, Manitoba. It also plans to have increased access to Canadian gas through its participation in the proposed Iroquois/Tennessee system and through an interconnection with the proposed Champlain pipeline.

MGT consists of two separate pipeline systems - a northern system supplied by Canadian gas and stretching from Emerson, Manitoba through Minnesota and Wisconsin, and a southern system, not served by Canadian gas, running from the interconnections with Tennessee Gas Pipeline at Portland, Tennessee to the Chicago, Illinois area which is the company's major market. Neither ETNG nor CIG are presently served by Canadian gas.

Tennessee stated that on a dedicated supply basis, Canadian gas represented some 6.7 percent of its current supply.

A&S, an Alberta based company, is a wholly owned subsidiary of Pacific Gas and Electric ("PG&E") which serves northern California. In 1988, A&S exported 10 877 10^6m^3 (384.7 Bcf) of natural gas to PG&E.

ANR is a major U.S. pipeline system serving the central U.S. In 1988, ANR imported 736 10^6m^3 (26 Bcf) of natural gas from Canada.

While EGS, PITCO and Tennessee were all interested in 20-year contracts with a constant annual level throughout the term, none of them would reject the opportunity to buy Delta gas if the term were shorter and the annual quantities less. However, these buyers considered that a step-down in annual quantities would be less desirable because such a step-down would adversely impact the economics of future pipeline facilities. Generally, the U.S. buyers agreed that a delay in the proposed 1996 start-up date of the project, a shortening of the 20-year term, or a reduction in term volume, would reduce the overall attractiveness of the project. It was stated that in some instances, these factors could persuade certain U.S. buyers to seek alternative sources of supply.

Texas Eastern was not prepared to clearly define any flexibility in the 4.2 $10^6m^3/d$ (150 MMcfd) volume in the Precedent Agreement and, at this time, was not interested in entering into a contract for less than twenty years.

Views of the Board

The Board concurs with the Applicants that access to the export market is essential to the development of Mackenzie Delta reserves.

The Board notes that the GRI study, adopted by the Applicants to illustrate the natural gas supply/demand balance for the lower 48 states, indicates that the U.S. market regions, particularly those

dependent on Canadian supplies, show a great need for Canadian natural gas. The Board accepts the Applicants' position that the U.S. markets are in need of natural gas imports from Canada and will continue to be so.

While the Applicants have entered into Precedent Agreements with potential U.S. buyers, the Board notes that there are no firm contracts for the volumes proposed for export. The Board agrees, however, that the granting of an export licence would provide the Applicants a better opportunity to contract.

The Board recognizes that the potential U.S. buyers are established importers of Canadian natural gas; the evidence indicates that those buyers are major participants in the United States gas market. The Board is satisfied, therefore, that there is a reasonable expectation that U.S. buyers will have sufficient markets to accommodate the level of exports contemplated in the applications.

3.2 Contracts

The Applicants submitted several Precedent Agreements with U.S. buyers expressing the buyers' intentions to enter into sales contracts for Mackenzie Delta gas. The Applicants acknowledged that, while these arrangements do not constitute executed export contracts, they illustrate a strong interest in the United States for Delta gas.

The Precedent Agreements with the U.S. buyers commit the Applicants and the purchasers to enter into contracts for a portion of the Delta gas volumes by a specified future date. The term of those contracts would be twenty years from the date of first delivery. The agreements indicate that the buyers expect to purchase a share of the gas available for sale and state that the buyers' share will be specified in the contracts.

The Precedent Agreements also state that the contracts to be negotiated will provide that demand charges would be paid by the buyers based upon tolls and tariffs as approved by the Board and any other governmental authority having jurisdiction. The buyers' payments of such charges would be subject to U.S. regulatory and governmental authorizations satisfying the buyers that they could recover the costs in their rates.

The agreements state that the point(s) of export shall be mutually agreeable to all parties.

The Precedent Agreements contain a provision for termination without liability upon sixty days written notice if either party believes that the gas reserves in the Beaufort would be insufficient to support the contract. The agreements could also be terminated if either party believes that the costs to produce and transport the gas to market would result in either an uneconomic project or uncompetitive gas prices. If either party believes that it would not be possible to obtain, in a timely manner, all the necessary regulatory approvals on acceptable terms and conditions, the agreement could be terminated. Finally, if both the buyer and seller could not enter a contract incorporating these terms and such other terms as either party deems necessary, the agreement could be terminated.

Both the agreements and the contracts can be assigned to any affiliate or subsidiary of either buyer or seller so long as the assignee adopts and is bound by the terms and conditions expressed in the agreement or contract.

The Applicants described the approach they plan to follow for negotiating final gas sales contracts and stated that they expect negotiations with Canadian and U.S. buyers to occur concurrently. The Applicants undertook to keep the Canadian marketplace informed about the progress of their negotiations with U.S. buyers. As well, each Applicant undertook to file export contracts with the Board. In the applications, it was assumed that the contracts would be negotiated by 30 June 1990 but, during the hearing, parties conceded that this date could be delayed by up to a year or more.

The Consumers' Gas Company Ltd. ("Consumers") stated that there should be some assurances from U.S. buyers that they would be allowed, through their regulatory process, to make commitments to recover the demand charges on the pipeline. The Minister of Energy for Ontario ("Ontario") held a similar view mentioning that the commercial viability of the project depended on the ability to pass through Canadian and U.S. pipeline demand charges.

Views of the Board

These Precedent Agreements are an expression of interest to purchase a portion of Delta gas and do not represent firm contracts. The Board agrees that any licence which might be issued by the Board should include a condition requiring the filing of each executed export contract for review and approval by the Board, to ensure that the contracts are consistent with the evidence submitted at the hearing.

When filing contracts, either separately or collectively, the Applicants would be required to advise all parties to the hearing of the filing of such contracts and would be required to serve copies of the filing on those parties who so requested it.

The Board would review the terms of export contracts to ensure that they represented substantive commercial arrangements consistent with the licence and the evidence provided at the hearing. Consideration would also be given to the degree of commitment to pass through demand charges.

If the Board were satisfied with a contract, and no complaints had been filed and sustained, the contract would be approved and the volumes relating to that contract could be exported. The complaints mechanism is more fully discussed in Chapter 5.

Transportation

Transportation of Delta gas to market would require new pipeline facilities. Before such a pipeline could be constructed, however, an application would have to be made to the Board for a certificate to construct and operate the pipeline. The Board would then hold a hearing to consider that application for a pipeline certificate. At that hearing, the Board would examine and make findings on the economic, technical, environmental and socio-economic issues related to the pipeline.

Nonetheless, in this proceeding, to satisfy itself about whether the proposed exports are in the public interest, the Board indicated its intent to consider all relevant public interest matters. These included the broad issue of the cost of transporting Mackenzie Delta gas to market.

The Board's evaluation of the Applicants' benefit-cost analysis required the identification of all incremental costs associated with the proposed exports. Incremental pipeline costs, an important component of this analysis, were thus examined in this export licence proceeding.

For the purpose of analyzing project economics, the Applicants estimated pipeline costs for a hypothetical pipeline following the Mackenzie Valley route and a new pipeline with separate legs from Caroline to Monchy, Saskatchewan and from Caroline to Kingsgate, B.C. These costs were used by the Applicants in their benefit-cost analysis and are summarized in Table 4-1 below:

Table 4-1

Pipeline Costs[1]

Facilities	Capital Costs ($ millions 1988)	Operating Costs ($ millions 1988/year)
Delta to Caroline	4,889	66.0
Caroline to U.S. Border	1,007	6.7

1 Undiscounted and excluding interest during construction.

The Applicants also indicated that capital cost estimates for three known alternative pipeline proposals "generally support(ed)" their own estimates.

The Applicants provided evidence on a preliminary design concept for these hypothetical facilities including a breakdown of the capital costs into the main elements, the annual fuel volumes, a breakdown of annual operating costs and details of the methodology used to prepare the conceptual design and to estimate the associated capital and operating costs along with a statement of major assumptions.

While the Applicants did not provide specific cost estimates to move gas to Niagara, they did include the Niagara volumes in their benefit-cost and financial analyses.

The Dene/Metis Negotiations Secretariat ("Dene/Metis") expressed concerns that the Applicants did not include socio-economic costs in their capital cost estimates.

Foothills Pipe Lines (Yukon) Ltd. ("Foothills") did not oppose the issuance of the proposed export authorizations "if properly conditioned", and "provided that all present and future Board orders relating to the exports remain fully consistent with the bilateral agreements, regulatory authorizations, and legislation relating to the construction and operation of the ANGTS." Foothills further emphasized that it "would oppose the applications if the proposed exports were part of any scheme to construct a pipeline system across the North Slope of Alaska and Canada to the Mackenzie Delta in order to provide for transportation of both Alaskan North Slope gas and Delta gas along the Mackenzie Valley. Foothills remains opposed to a

North Slope pipeline for Alaskan gas because such a pipeline would be totally inconsistent with ANGTS". Foothills hence requested that the following statement be inserted in any licences which might be issued: "... the granting of the export licences herein is consistent with the commitments of the two countries in that Agreement and, in particular, the route selected for the transportation of Alaska gas described therein".

In response to a question from Ontario, the Applicants indicated that "the normal requirements of a future facilities application would include a re-examination of the benefit-cost implications of the project".

Views of the Board

The Board notes that none of the interested parties questioned the capital cost estimates, the operating cost estimates or the conceptual pipeline design provided by the Applicants. The concerns that were expressed regarding route selection and socio-economic costs would be thoroughly covered in any future facilities hearing.

The Board is also of the view that, to assess the benefit-cost of these export applications now, it is reasonable to base, provisionally, pipeline cost estimates on a hypothetical pipeline following the Mackenzie Valley route and on a new pipeline with separate legs from Caroline to Monchy and Kingsgate. Although other transportation alternatives have already been identified, they all involve similar pipeline lengths.

The Board is satisfied that the proposed conceptual design should be fully capable of moving the specified volumes. The Board recognizes, however, that these hypothetical facilities estimates are provided only to demonstrate project viability. Technical feasibility, design optimization and pipeline costs would be examined in more detail as part of any future facilities hearing.

The Board also notes that:

- the Applicants' estimates are based on what they consider to be a viable transportation system;

- the capital cost estimates for this hypothetical pipeline system attempt to reflect a normal level of pipeline construction activity, rather than the low activity and the correspondingly lower prices for materials and labour that have been in place over the last few years;

- the Applicants have made an effort to set the contingency factor at a level they consider adequate to account for the uncertainties about the route, the timing and the conditions of construction of such a pipeline; and

- the Applicants did not attempt to identify the cost savings or economies of scale that might accrue to upgrading existing facilities and assumed that a new dedicated pipeline would be built south of Caroline.

Based on the above, the Board concludes that the Applicants' capital cost estimates are adequate to conduct a benefit-cost analysis of the proposed exports under Part VI of the Act.

In the Board's opinion, the Applicants' estimates of fuel consumption to Kingsgate and Monchy are realistic. Operating costs for this hypothetical pipeline system have not been examined in detail, and uncertainties in estimating unit operating costs remain. Consequently, sensitivity analyses of how the net benefits to Canada could be affected by higher operating costs and by changes in capital cost estimates were conducted. The results are presented in the benefit-cost Chapter of this report.

Turning to the Foothills request, the Board is of the view that it would not be necessary or desirable to recognize in any licences which might be issued existing bilateral agreements respecting the ANGTS. None of the interested parties submitted evidence suggesting that the granting of export licences would interfere with the ANGTS treaty. The Board believes that the granting of any export licences would not be inconsistent with the commitments of Canada and the United States in the ANGTS treaty. The Board is also of the view that it would be inappropriate to recognize any specific pipeline route in any licences which might be issued, as that matter is beyond the scope of this proceeding. That is, in the Board's view, a facilities matter which would be thoroughly addressed in any future facilities hearing.

Chapter 5

Availability of Gas to Canadians

Three issues were raised at the hearing concerning the availability of gas to Canadians.

The first related to the Applicants' negotiations and discussions with potential buyers. The hearing addressed the timing of negotiations, the Applicants' expected date for execution of signed purchase contracts and how Canadian companies could accommodate this schedule.

The second issue, relating to the Precedent Agreements and execution of signed export contracts, was the Board's Complaints Procedure, and how various parties felt it could work, given the character of these applications.

The third issue was the availability of Delta gas supplies to meet the requirements of Northern communities.

Contract Negotiations

The Applicants expressed their willingness to conclude long-term sales contracts with any customer who is prepared to purchase Delta gas on competitive terms and in a timely manner. As noted in Chapter 3 they have signed Precedent Agreements with several potential U.S. buyers and have, in most instances, met with and discussed the requirements of major Canadian natural gas distributors for Delta gas. While Esso, Shell and Gulf expect to execute signed contracts by 30 June 1990 they admitted that negotiations might delay this target date by one year to 30 June 1991. However, they also indicated that they expect potential Canadian and U.S. buyers to negotiate concurrently, in order that interested buyers from both countries would be prepared to execute signed contracts according to this schedule. Once contracts were executed, the Applicants would dedicate the contracted volumes to the specific buyers and such base volumes would not be available to other parties in the future.

Several major Canadian distribution companies - Gaz Métropolitain inc. ("GMi"), The Consumers' Gas Company Ltd., Union Gas Limited ("Union"), ICG Utilities (Ontario) Ltd. ("ICG") and Greater Winnipeg Gas Company ("Greater Winnipeg")- presented witness panels, at the request of the Board. As well, these companies and the Industrial Gas Users Association ("IGUA") responded to a Board Information Request, relating to requirements for Delta gas in their franchise area and to their discussions with the Applicants in this respect.

The applications included letters of support from several Canadian local distribution companies ("LDCs"), indicating their interest in the project as a means to develop additional natural gas supply sources. At the time of the GH-10-88 Hearing ("the Hearing"), no Precedent Agreements had been signed with potential Canadian customers, although Union indicated its intent to sign. Consumers initially expressed the view that it was unwilling to commit to a Precedent Agreement, on the assumption that commercial contractual terms would be specified. However, on review of the Precedent Agreement signed by the Applicants and potential U.S. buyers, Consumers stated that it may reconsider its position. Consumers viewed such a Precedent Agreement as simply a statement of intent to purchase the gas when it flows, if it is competitive with other sources of gas in Consumers' market and if regulatory bodies would permit recovery of costs in Consumers' rates.

The extent of discussions between the Applicants and the individual utilities, prior to the hearing, varied. In most instances (Consumers, ICG, Union, GMi), discussions were of a preliminary nature, with no reference to minimum contract volumes, terms, or start dates acceptable to the Applicants. However, Greater Winnipeg had not had discussions with the Applicants.

No distributor at the Hearing felt constrained by the terms of its existing contracts from negotiating

for purchases of Delta gas. In particular, all utilities expressing an interest in Delta gas viewed the non-self-displacement provision in their recently signed contracts with Western Gas Marketing Limited ("WGML") as a business agreement which was not necessarily a constraint to negotiating for other supplies. Each company did, however, outline the characteristics of its own market environment which affected the extent of its negotiations with the Applicants.

Two companies stated that they would not be pursuing acquisition of Delta gas supplies to meet the needs of their franchise area.

Greater Winnipeg testified that it is unable at this time to determine whether it would require Delta gas. Its market is small and the company feels that there may be sufficient supplies available from conventional areas to meet its requirements. As Greater Winnipeg's current supply arrangement with its sole supplier WGML expires in 2003, the company does not expect to seek incremental supplies until about the year 2000, at which time, under normal supply/demand conditions it would renegotiate its gas supply. If the supply situation appeared less favourable over time, Greater Winnipeg would go to the market at an earlier date to negotiate for supplies after 2003. At such a time, Greater Winnipeg would assess all available gas supplies to select its supply source(s). For these reasons, Greater Winnipeg Gas is not prepared to enter into an agreement with the Applicants by the 30 June 1990 (or 1991) date.

GMi stated that Delta gas was one of several alternative potential supply sources which might be required sometime between 1996 and 2003 at which time its long-term contracts, currently supplying 47 percent of its market, expire. However, GMi stated that it has chosen not to pursue a portion of the Delta gas volumes under consideration for export, as it believes that alternate supply sources might be less expensive. Further, GMi does not make supply decisions for the large portion of its clients who arrange for their own gas supply.

At the hearing, the remaining three Ontario distributors expressed an interest in the Delta gas volumes. Consumers ultimately indicated that there is a possibility of it signing a contract with the Applicants prior to 1991. Close to 50 percent of Consumers' market is currently supplied through long-term contracts of 10-15 years duration. Consumers felt that the size of contracts being discussed by potential buyers, 1.4 to 4.2 $10^6m^3/d$ (50 to 150 MMcfd), is well within Consumers' capability and could be accommodated in its portfolio of gas supplies. In terms of factors which might inhibit Consumers' negotiations with the Applicants, the company mentioned regulatory approvals by the Ontario Energy Board to recover costs, and the distributor's requirement to serve the core market, although there is still some fluidity and uncertainty in the size and composition of this market.

Consumers views Delta gas as one of several supply sources potentially available to it. In terms of its current contracting practices, Consumers said that the surplus in natural gas markets has allowed it, in the recent past, to meet its needs with shorter term contracts, more so than under tighter market conditions. As supply tightens and there is a perception of shortage, Consumers stated that "each responsible buyer (will) have to lengthen its planning horizons and, obviously, take some longer-term risks".

ICG recently concluded a 15-year contract with WGML and indicated that prior to the expiry of this contract in 2003, it did not anticipate any substantial need for Delta gas. However, ICG stated that it would be difficult to quantify its need for Delta gas after 2003 as its residential and commercial sector was not experiencing much growth, while 70 percent of its supply requirements are tied to commodity industries which are typically subject to wide fluctuations in activity. Although ICG does not expect to be in a position to execute a signed contract by the 1990-91 deadline, it has asked the Applicants to keep it informed, so that it can maintain an on-going review of the market situation. While it is the Applicants' stated objective to execute signed contracts for the full 260 10^9m^3 (9.2 Tcf) by 1990-91, at which time contracted volumes would be dedicated to buyers, ICG's view was that there would have to be drastic changes in the marketplace between now and 1990-91 for this to be achieved. ICG also stated that it would be concerned if by 1990-91 the full 260 10^9m^3 (9.2 Tcf) were committed to the export market.

During the course of the Hearing, Union expressed a desire to sign a Precedent Agreement and to pursue negotiations to execute a signed contract by

1990-91, although it questioned whether the Applicants would be in a position to specify contractual terms and conditions by that time. Union argued that "... it appears premature at this time for the Applicants and others to enter into meaningful Precedent Agreements, let alone sales contracts." Union said that the evidence confirmed that Union and other domestic gas users are expected to require Delta gas to meet future requirements. Union's present estimate of annual requirements for Delta gas from 1996 is in the order of 850 10^6m^3 (30 Bcf).

Thus, while GMi and Greater Winnipeg clearly stated that they will not pursue negotiations with the Applicants for the applied-for volumes, Union indicated an intention to enter negotiations, and Consumers and ICG expressed a desire to continue discussions, although they are unsure whether they would enter into agreements by the stated deadline.

Complaints Procedure

Each Applicant expressed an intention to file executed export contracts with the Board to allow Canadians to review the terms and conditions to determine whether there was a basis for complaints. However, the Applicants attached several caveats to this statement. They would expect interested Canadian buyers to have been attempting to buy and to have been negotiating with the Applicants up to the time export contracts are executed. They would not accept that Canadian buyers remain inactive until the export contracts were filed, and at that time express an interest based on the terms and conditions negotiated in the executed contracts. Further, the Applicants expressed the view that they would expect dissatisfied potential buyers to have exhausted their opportunities for obtaining gas elsewhere in Canada and in the United States and to be able to demonstrate, as a result, that they were unable to purchase gas on similar terms and conditions.

The Applicants were questioned on their interpretation of "similar terms and conditions" as specified in the Complaints Procedure. Esso indicated that although most people would consider price as one of the most important terms and conditions, other factors, such as the degree of commitment to demand charges and the financial integrity of the buyers, would also be important components of the contract. Gulf expressed the view that identical netbacks from all buyers would not be necessary, due to differing regional markets and competing fuel situations. However, in the event of a complaint, the Board would determine whether, in fact, the terms and conditions were similar.

The Applicants view an export licence as a means of establishing non-discriminatory access to the marketplace - in both the U.S. and Canada - and were concerned that a requirement to satisfy the Complaints Procedure prior to the issuance of a licence would be a setback to the project. Shell stated that U.S. buyers have indicated in discussions that they have "little time to spend with people who come to them to sell gas who do not have an export licence", and that the lack of an export licence places Canadian producers at a disadvantage in marketing their natural gas.

Esso, Shell and Gulf expressed a willingness to negotiate with potential Canadian buyers concurrently with U.S. buyers, to ensure that potential buyers have sufficient information to negotiate and to avoid a situation of possible complaints once executed contracts are filed with the Board.

In the absence of export contracts with specific terms and conditions, the Applicants admitted that the Complaints Procedure, as established by the Board, cannot operate. They indicated that they would accept, as a condition of any licence they might be issued, a requirement to file executed export contracts with the Board for review by Canadian buyers to determine whether there were bases for complaints. Provided that the negotiating process envisaged by the Applicants were followed, the Applicants would be willing to accept this condition to satisfy the Complaints Procedure.

All local distribution company intervenors (except GMi) were asked their views on the working of the Complaints Procedure in the context of these Applications. (GMi stated clearly that it was not interested in negotiating for the Delta gas volumes under application and therefore it would have no basis for complaints.) Greater Winnipeg was concerned that the Complaints Procedure is not forward-looking, in that it does not concern itself with the situation which might arise 15 years from now. Greater Winnipeg said that if it were not interested in buying gas right now, it should have no basis for a serious complaint; it was nevertheless concerned that export licences could tie up

large volumes of gas, leaving little uncontracted gas available when Greater Winnipeg returns to the market to negotiate its supplies for the post-2003 period.

Consumers viewed the Complaints Procedure as a means by which the Board could ensure that Canadians and Americans have equal opportunity to purchase gas on competitive terms and conditions, through concurrent negotiations with an Applicant. Consumers felt that it would be very difficult for potential buyers to complain effectively, at this time, since the Precedent Agreements do not specify contractual terms and conditions. Complaints could not be retroactive, but would occur only at the time final contracts were presented to the Board. Given these difficulties with the Complaints Procedure, the long lead time and the unique nature of this project, Consumers did not think that "the Board is in the position of determining whether a definite licence could be granted at this time".

ICG expressed views similar to Consumers' on the complaints mechanism. While ICG did not believe it had a basis for complaints during the Hearing, as it currently has a long-term supply for gas, it also observed that there are no terms and conditions attached to the U.S. Precedent Agreements. ICG requested equal opportunity to purchase Delta gas, although admitting that under the current market situation it is not prepared to enter into a Precedent Agreement with the Applicants.

Union Gas found the Complaints Procedure to be fundamentally unworkable in the context of this Hearing, and expressed concern about whether it could ever be effective. Union stated that while it is concerned about the gas market 12-15 years from now, it cannot complain today about what might happen at that time, since it is not in a position to buy gas supply to start flowing in 12-15 years. Union has not contracted on such a basis, as it states that producers are generally unwilling to agree to such terms, preferring contracts which commence in the short term. Union is, however, prepared to consider contracts with the Applicants for volumes commencing in 1996.

Union questioned whether the Board could deem the Complaints Procedure to be satisfied if there were no complaints, when there may be buyers who did not come forward due to lack of knowledge or understanding of the gas market. Union's interpretation of the Complaints Procedure is that a complaint can exist only if the buyer cannot purchase gas from any source at that point in time on similar terms and conditions. However, Union's concern is that the Complaints Procedure does not effectively deal with situations which could arise over the long run. It also suggested that the Market-Based Procedure should pay more attention to uncontracted gas, rather than gas supplies.

IGUA, in response to an Information Request issued by the Board, stated that industrial gas users seldom have a supply contracting horizon greater than five years, and therefore it is unreasonable to expect them to predict and contract for specific volumes of gas to protect their needs to 2016. IGUA further stated that it was concerned that Delta supplies must be available for use by the Canadian market as the need arises. IGUA members had not had any discussions with the Applicants, nor were they prepared to enter into a Precedent Agreement or contract by 30 June 1990. IGUA, in declining the Board's request to present a panel, responded that it is not possible for industrial gas users to complain, due to their practice of contracting for a period of five years. IGUA suggested that the Board make "the export licence subject to conditions that will operate to assure that Canadian users will have access to the gas under licence when it has been determined, by the National Energy Board, that the gas is needed to serve the reasonably foreseeable requirements of Canadians".

Apart from concerns about the effectiveness of the Complaints Procedure, and comments relating to contractual terms, as discussed above, no local distribution company or provincial government opposes the project. Several intervenors provided suggestions as to how to satisfy the Complaints Procedure in the context of this Hearing.

Both ICG and Consumers emphasized that they were requesting equal opportunity and not preferential treatment relative to potential U.S. purchasers of the gas. Consumers recommended that the Board approve in principle and issue a conditional licence which would require the Applicants to file executed contracts. At such a time, if there were no complaints, the Board could issue a definite licence.

ICG referred to the Board's GHR-1-87 Decision where it states, with respect to the Complaints

Procedure that "much might hinge on the equivalence of the contractual terms in the export arrangement". Based on this and on Section 118 of the Act, ICG concluded that the Board "effectively has no choice but to provide in its Decision for a review of any and all export contracts which may be executed between now and the June 1991 date suggested by the Applicants, prior to issuing any unconditional export licence".

Ontario submitted that "for the Complaints Procedure to work effectively, gas sales contracts need only be filed subsequent to the Board's granting this export licence".

Union, in argument, suggested that the Board attach conditions to any licence which would require the Applicants to inform potential Canadian buyers of their intentions; conduct reasonable negotiations with potential Canadian gas purchasers; and inform the Board where such negotiations are not successful and contracts are to be signed for the export of gas. Union also indicated that it would support Consumers' proposal of approval in principle followed by a definitive licence once complaints are satisfied. Union stated that since it feels it is premature to enter into sales contracts "... the Board must give more attention to the Export Impact Assessment, and in particular, to the amount of uncontracted gas available for Canadian users, along with other factors it considers relevant, in carrying out its mandate under Section 118(a) of the National Energy Board Act".

Le Procureur général du Québec ("Quebec") recommended that the Board issue a conditional licence which would require the Applicants to determine the requirements of both U.S. and Canadian consumers for the gas, after which a definitive licence could be issued. Quebec asked the Board to take into consideration certain differences between Canadian and U.S. natural gas markets. In particular Quebec noted that in Canada certain "non-core" customers are responsible for securing their own supply of natural gas. In the case of Quebec, where such customers comprise 53 percent of the gas market, this makes it difficult for the province to contract now for a twenty year period beginning in 1996, due to the instability of these customers' demands. Quebec also stated that it encouraged the Board to review its existing procedures used to protect Canadian requirements, as Quebec feels that this procedure may not allow all Canadians the same opportunity to obtain secure supplies of natural gas. Quebec did not provide any elaboration of its argument.

Views of the Board

The Complaints Procedure is intended to ensure that Canadians have an equal opportunity to purchase natural gas on terms and conditions similar to those offered other participants in the country's natural gas markets.

The Applicants filed Precedent Agreements which had been signed with several U.S. companies and there was an indication that certain Canadian distributors might be interested in signing similar agreements. However, no executed contracts with well-defined terms and conditions have been negotiated by the Applicants. The Board agrees with all parties who expressed views that the Complaints Procedure cannot fully operate in the absence of contracts with specific terms and conditions. Potential buyers must be able to review the terms and conditions of executed contracts to determine whether, as a result of their negotiations with the Applicants, or from other sources in the market, they were able to purchase gas on a similar basis.

Given current arrangements in Canada's natural gas markets, the Board recognizes the possibility that Canadian purchasers may face constraints, not necessarily faced by potential American buyers, in negotiating or entering into contracts with defined time periods or volumes. Most distribution companies intervening at this Hearing had recently negotiated long-term gas supply arrangements with WGML, which extend for the next ten to fifteen years. As these volumes account for from less than 35 to as much as 100 percent of distributor requirements, the scope for making large commitments for Delta gas by these distributors is reduced during the period of the contracts with WGML. These contracts also include non-self-displacement provisions. However, no intervenor identified any condition or constraint, in its existing contracts, to which they had not agreed in the course of normal business practice.

The Board agrees with those intervenors who expressed the view that the timing of deliveries under this project, with natural gas volumes to begin flowing only in 1996, is unusual. As such, it does represent a change in contracting practice, as distributors are accustomed to contracting for

delivery commencing in the short term reflecting most producers' desire to have gas flow begin as soon as possible. However, the Board views individual contracting practices - whether they be for short-term contracts only, or for a single long-term contract from a single supplier - as a reflection of the consumer's assessment of risk. IGUA members' practice of contracting for a five-year period reflects their business assessments of the risks and costs associated with various contract terms. Similarly, those consumers who choose to contract for their own supply of natural gas through direct sales or similar arrangements, also make their own assessment of the costs and risks associated with different contract terms. While the Complaints Procedure is intended to allow the Board to determine that all parties have had equal opportunity to contract for natural gas, it is not intended to provide preferential arrangements for consumers whose assessment of market risks leads them to choose contract terms different from those negotiated between other parties in the natural gas market.

The Board agrees with the Applicants that Canadian potential buyers must be prepared to negotiate in the same time frame as U.S. purchasers, and concurs with parties to the Hearing who requested equal, but not preferential treatment with a view to concurrent negotiations. The Board is encouraged that the Applicants will provide all interested parties with equal opportunity to negotiate for volumes of Delta gas on similar terms and conditions.

In order to ensure that potential buyers are fully informed on the progress and expected filing date of executed export contracts, and to facilitate concurrent negotiations of potential Canadian and U.S. buyers with the Applicants, the Board would require, as a condition of any licence which might be issued, that the Applicants advise potential Canadian buyers who have declared an interest in buying gas from the Mackenzie Delta region of the quantities available for sale and give them an opportunity to purchase gas from the Mackenzie Delta region on terms and conditions, including price, similar to those under which the gas would be exported.

Several intervenors and the Applicants recommended that the Board include in an export licence a condition requiring filing of all executed contracts for review by Canadian consumers, to determine whether, among other things, there is a basis for complaints. However, no intervenor objected to the project on the grounds that it was currently prevented from having equal opportunity to buy this gas.

The Board recognizes that in the absence of contracts containing terms and conditions of the proposed export, the Complaints Procedure cannot operate as it would if there were contracts before the Board underpinning the applications. Therefore, the Board agrees with proposals to include a condition in any licence which might be issued, requiring filing of all executed contracts, and providing a timely opportunity thereafter, say 60 days, for interested parties to complain.

Such a licence condition would allow Canadian customers to review the terms and conditions of signed export contracts in order to determine whether they were able to execute agreements similar to the export arrangements. It would not, however, provide preferential treatment. The Complaints Procedure provides for a one-time opportunity to register complaints about relative contract terms and conditions for domestic and export proposals. It does not provide an opportunity for potential buyers to complain at some future date during the life of the contract.

If on reviewing the terms and conditions of the executed export contracts, a potential buyer felt it had a basis for a complaint, it must be prepared to prove to the Board that it had been attempting to buy gas and had been negotiating with the Applicants. Furthermore, the buyer would have to demonstrate to the Board that it had pursued other possible sources of natural gas supply and was, as a result of such efforts, unable to obtain gas supplies on similar terms and conditions.

The Board is satisfied that with these conditions, the objectives of the Complaints Procedure could be fulfilled.

Gas for Northerners

The Applicants testified that they were prepared to negotiate contracts to supply gas to markets which could develop in the North and that the price, exclusive of transportation costs, would be significantly lower than the comparable price in southern Canada (i.e. southern Canada price less transportation costs).

One of the stated purposes of the proposed Northern Accord between the Government of Canada and the Government of the Northwest Territories ("GNWT") is "to achieve the orderly development of oil and gas resources for the benefit of Canada as a whole and the Northwest Territories in particular." In this connection, several submissions by Northerners expressed the view that Mackenzie Delta gas should be made available for local use at reasonable prices.

In its submission, the Northwest Territories Federation of Labour said that energy costs were a major contributor to the high cost-of-living in the Northwest Territories, and suggested that the Board should look carefully at whether Northern communities would benefit from the proposed exports by receiving access to affordable supplies. The Northwest Territories Legislative Assembly also referred to the importance of cost and security of energy supply to Northern residents. The Town of Inuvik said that it wished to have access to Delta supplies at reasonable rates as did the City of Yellowknife and the Hamlet of Fort McPherson.

The Hamlet of Tuktoyaktuk ("Tuktoyaktuk"), a community of about nine hundred people, felt that the Applicants should be required to serve the energy needs of its citizens and others in the Western Arctic, at the earliest possible time. Canadians for Responsible Northern Development ("CRND") held a similar view. Tuktoyaktuk mentioned that the North experienced high energy prices and that development of gas reserves in the Mackenzie Delta should result in a reduction in costs. The Northwest Territories Power Corporation suggested that natural gas should be made available to any approved local distributor at a price no greater than the fieldgate price to exporters. Tuktoyaktuk indicated that the substitution of gas products, such as propane, for existing fuels could provide an extremely desirable benefit for residents of the Western Arctic. To this end, Tuktoyaktuk recommended that studies be undertaken to determine the feasibility of using propane and other gas products.

In its submission, the Inuvialuit Regional Corporation ("IRC") reported that energy costs in the North were two to three times higher than in other parts of Canada and that the availability of less expensive supplies from the Mackenzie Delta would be an important benefit to Northerners. In this connection, the IRC mentioned that the price of energy to final users could be reduced by some 30 to 40 percent in communities such as Inuvik. The IRC felt that the Applicants should be required to provide sufficient volumes of gas to satisfy the Northern demand and that this should be a condition of the licence. With regard to the price to be paid for the gas, the IRC suggested that it be based on the market price at the Canada/U.S. border, less transportation costs from the border to the point at which the Northern community accesses the gas. The potential benefits of using propane were outlined, particularly in communities that could not be economically served by pipeline.

Views of the Board

The Board recognizes that Northerners have experienced high energy prices for many years and that the supply of Mackenzie Delta gas and perhaps propane could substantially reduce costs. The Board notes that additional study needs to be undertaken by Northerners to determine the most economic fuel to be used in various communities. For those close to the pipeline, it could be natural gas while communities further away might decide to use propane. In any case, the volumes of gas to be used in the North would be relatively small compared with the quantities that would be transported to southern markets.

Based on the Applicants' stated undertakings, the Board expects that appropriate supply agreements will be negotiated with Northerners, with terms and conditions that would yield a price significantly less than the comparable price in southern Canada. The Board notes that the IRC and the GNWT would have access to gas supplies arising from royalty and working interest arrangements and that, if required, these sources, although not likely available until after 2003, could substantially meet the Northern demand at that time. The Board concludes that it would be difficult to include in any licence which might be issued a meaningful condition requiring the Applicants to supply natural gas to Northern residents because neither the routing of a pipeline nor the volumes of gas which might be required to serve Northern residents are known. In addition, such a condition is not necessary because of the Applicants' stated undertakings to provide gas to Northerners. This matter could be re-examined at the time of any future facilities application.

Export Impact Assessment

The EIA helps the Board to determine whether a proposed export is likely to cause Canadians difficulty in meeting their future energy requirements at fair market prices. An applicant is required to assess the ability of Canadian natural gas producers to meet Canadian and export requirements for gas; the impact of the proposed export on domestic natural gas prices; and the ability of Canadian consumers to adjust, if necessary, their energy consumption patterns without substantial difficulty.

The burden of proof is on the applicant to demonstrate to the Board that the proposed export will not likely lead to any major difficulty for domestic consumers in meeting their energy requirements at market prices. The EIA presented in support of the proposed gas export addressed the required issues.

In their initial applications the Applicants submitted an analysis which addressed some of the issues required by the EIA. In response to information requests issued by the Board, the Applicants conducted a quantitative analysis of the impact of exporting Delta gas on the total Canadian and North American gas production. This information indicates that total Canadian production would increase by no more than 500 Bcf/yr. The Applicant's project would develop in the range of 400-460 Bcf/yr.

In this quantitative analysis the Applicants stated that, while the simulations did not explicitly reflect the supply costs of Delta gas, the analysis was consistent with the costs shown in Table 6-1. These show the cost of Delta gas delivered to Caroline to be less than the price of Alberta gas over the entire period, and below Alberta average and marginal gas costs over most of the period. The supply costs for Delta gas shown in this table are broadly consistent with those discussed in Chapter 2.4 Natural Gas Costs.

The Applicants expressed the view that the impact of Delta gas would be to modestly lower North American gas prices in the late 1990s and beyond as compared to the level such prices would reach otherwise. This view was based on the general proposition that there will be competitive natural

Table 6-1

Comparison of Supply Costs[1]

1988 U.S. $/Mcf

Year	Alberta Marginal Cost	Alberta Average Cost	Delta Gas Cost Delivered to Caroline	Alberta Average Price
1997	2.23	1.77	2.68	2.94
2002	3.48	2.86	2.13	4.28
2007	4.76	4.12	1.90	5.59
2012	6.13	5.45	1.59	6.98
2017	7.70	6.91	1.35	8.25

1 From Ex. B-83, Response to I.R. No. 83, Page 5 of 10. Delta Gas Cost Delivered to Caroline reflects declining real transportation costs (i.e. not averaged, or levelized).

gas price formation in an open North American natural gas market, such that regional prices will adjust freely to balance supply and demand for gas. Without Delta gas, the Applicants argued that the market would call on the next higher cost source of gas, leading to higher gas prices.

In response to a Board Information Request, the Applicants provided quantitative information supporting its argument that natural gas prices would be lower with Delta gas than without it. The analytical framework which the Applicants used presupposes an open interconnected market without barriers to trade. In this framework, the introduction of new supplies to the North American market should have an impact on regional price formation throughout North America. The size of this impact is related to the size of the new supply relative to that of the market into which it is introduced.

The proposed supply of natural gas from the Delta region represents a relatively small portion of total North American future gas production (see Tables 6-2 and 6-3). According to this analysis, Canadian burner-tip gas prices would be 3.6 percent and

Table 6-2

Canadian Gas Production

Tcf/Year

Year	Without Delta Gas[1]	Assumed Delta Gas Volumes	With Delta Gas[2]	Difference[3] (Level)
1997	4.436	0.400	4.636	+0.200
2002	4.495	0.400	4.749	+0.254
2007	3.962	0.400	4.463	+0.501
2012	3.375	0.400	3.805	+0.430
2017	3.063	0.400	3.504	+0.441

1 From Ex. B-66, Response to NEB I.R. No. 59, Report No. 19
2 From Ex. B-72, Response to NEB I.R. No. 77, Attachment A, Page 1 of 4, Report No. 19
3 "With Delta Gas" less "Without Delta Gas"

Table 6-3

Total North American Gas Production

Tcf/Year

Year	Without Delta Gas[1]	Assumed Delta Gas Volumes	With Delta Gas[2]	Difference[3] (Level)
1997	19.504	0.400	19.644	+0.140
2002	19.015	0.400	19.194	+0.179
2007	17.332	0.400	17.888	+0.556
2012	17.121	0.400	17.338	+0.217
2017	16.748	0.400	17.016	+0.268

1 From Ex. B-66, Response to NEB I.R. No. 59, Reports No. 1 and No. 19
2 From Ex. B-66, Response to NEB I.R. No. 59, Report No. 1 and Ex. B-72, Response to NEB I.R. No. 77, Attachment A, Page 1 of 4, Report No. 19
3 "With Delta Gas" less "Without Delta Gas"

2.8 percent lower in 1997 and 2017 respectively with Delta gas than without it (see Table 6-4), inducing an additional 1.7 percent consumption of natural gas over the projection period (see Table 6-5). This occurs because the proposed exports displace the next costlier gas which would have been selected were it not for the availability of Delta gas.

The Applicants also concluded that Canadian consumers are capable of adjusting to changes in underlying market conditions in a measured, not traumatic, way.

Views of the Board

While the Board may not necessarily agree with all aspects of the methodology applied to determine

Table 6-4

Canadian Burner-tip Prices[1]
With and Without Delta Gas

1988$ US/Mcf

Year	Without Delta Gas	With Delta Gas	Difference[2] (%)
1997	5.22	5.03	-3.6
2002	6.67	6.50	-2.6
2007	8.16	7.89	-3.3
2012	9.53	9.27	-2.7
2017	10.96	10.66	-2.8

1 From Ex. B-33, Response to I.R. No. 29, page 7 of 12, Table R-29-3.
2 "With Delta Gas" less "Without Delta Gas" as percentage of "Without Delta Gas" case.

Table 6-5

Canadian Gas Consumption[1]
With and Without Delta Gas

Tcf/Year

Year	Without Delta Gas	With Delta Gas	Difference[2] (%)
1997	2.557	2.597	1.6
2002	2.692	2.736	1.6
2007	2.781	2.832	1.8
2012	2.949	3.000	1.7
2017	3.166	3.220	1.7

1 From Ex. B-33, Response to I.R. No. 29, page 11 of 12, Table R-29-7
2 "With Delta Gas" less "Without Delta Gas" as percentage of "Without Delta Gas" case.

the impact of Delta gas on natural gas prices, demand and supply, the Board does not disagree with the Applicants' general conclusion. The Board agrees with the conclusion that the proposed export is likely to have a small downward impact on domestic natural gas prices, given the continuation of an open market trading environment.

Adjustments in the gas market could be difficult to achieve if large increases in gas prices were predicted, causing gas users to want to switch to other fuels. However, availability of Delta gas is expected to moderately reduce gas prices; therefore little or no disruption of consumer habits is anticipated on this account.

In light of the above assessment, the Board agrees that the applied-for export volumes are not likely to cause Canadians difficulty in meeting their future energy requirements at fair market prices.

Benefit-Cost Analysis

In support of their applications, Esso, Shell and Gulf submitted the benefit-cost analysis which is summarized in Table 7-1. The initial analyses provided for the Esso and Shell applications were based on the world oil price assumptions and the domestic demand projections included in the Board staff's October 1986 Report *Canadian Energy Supply and Demand, 1985-2005* ("October 1986 Report"). When the benefit-cost analysis was updated to include the Gulf volumes, the results were provided both under the initial October 1986 Report assumptions and those of the September 1988 Report. The summary provided here discusses the results based on the more recent September 1988 Report.

The Applicants' analysis indicates that the applied-for exports would yield net benefits to Canada ranging between $1.3 billion (PV$)[1] and $2.5 billion (PV$) in their low and high price cases[2] respectively, with all project benefits and costs discounted at 8 percent real.

The Applicants' low and high world oil price scenarios are distinguished by different assumptions about future natural gas prices, costs and demand. The Applicants' estimate of gross social benefits consisted of natural gas revenues associated with the sale of the proposed exports at the Canadian border plus the revenues from the sale of by-products obtained by gas processing. Since no export sales contracts have been signed as yet, there are no identified export points. For the purposes of illustrating the project economics, the Applicants' analysis assumed that initially export volumes would be 223 PJ (212 Tbtu) per year at Kingsgate, 223 PJ (212 Tbtu) per year at Monchy and 41 PJ (39 Tbtu) per year at Niagara. The distribution of exports by border point was held constant over the project term.

1 *PV$* mean 1988$ discounted at 8 percent real.

2 *Low and high price cases* refer to a low world oil price scenario and a high world oil price scenario.

Table 7-1

Proposed Mackenzie Delta Export
Esso/Shell/Gulf Benefit-Cost Analysis

(billions of 1988$, discounted at 8%)

	Low World Oil Price	High World Oil Price
Export Revenue	8.4	11.3
Condensate Revenue	0.7	1.1
Less:		
Production Costs	2.5	2.5
Gas Transmission Costs	4.1	4.1
Condensate Transportation Costs	0.3	0.3
Equals:		
Net Direct Benefits	**2.2**	**5.5**
Plus Indirect Adjustments:		
Labour Externality	0.2	0.2
Duties, Foreign Financing Flows and Foreign Exchange Externality	0.4	0.6
User Costs	-1.5	-3.7
Net Indirect Adjustments	-1.0	-3.0
Equals:		
Net Social Benefits	**1.3**	**2.5**
Benefit/Cost Ratio	**1.16**	**1.24**

Export revenues were then estimated for two projections of natural gas prices at Kingsgate, Monchy and Niagara. These projections were predicated on the high and low world oil price assumptions contained in the September 1988 Report. Export sales revenues were estimated to be $11,344 million (PV$) and $8,368 million (PV$) in the high and low price cases.

The only by-products assumed in the analysis were the condensate removed from the Esso and Gulf volumes at the field processing plants. The initial condensate volumes of 1 170 10^3m^3 (7,359 10^3 barrels) per year were assumed to decline after 2005 to reflect, first, the changing content of the reserves scheduled to be connected and, then, the declining gas volumes. Condensate prices were assumed to be constant in real terms and to equal $221/$m^3$ ($35/barrel) (1988$) in the high price case and $143/$m^3$ ($23/barrel) (1988$) in the low price case. By-product revenues were estimated to equal $1,105 million (PV$) and $715 million (PV$), in the high and low price cases.

Production costs associated with the development wells, gathering lines, processing plants and, later in the project term, offshore islands needed to support the proposed export volumes were estimated to equal roughly $2,520 million (PV$). Unit social supply costs[1] at the plant-gate associated with the Esso, Shell, and Gulf volumes were assumed to equal $1.00/GJ ($1.05/MMbtu) (PV$). All costs incurred prior to 1989 are sunk and thus were excluded from this estimate.

As discussed in Chapter 4, delivery of the gas and condensate to markets would require the construction of separate new pipeline facilities. The benefit-cost analysis included a cost of $3,341 million (PV$) for a hypothetical natural gas pipeline with a capacity of 489 PJ (465 Tbtu) per year from the Mackenzie Delta to Caroline, Alberta. The non-fuel operating costs included in this estimate were $66 million (1988$) per year. Fuel loss was assumed to be 3.8 percent.

The present value of capital and operating costs for transmission of the proposed exports from Caroline to the U.S. border was estimated as $716 million (PV$). This was based on the cost of a hypothetical pipeline having two legs, one from Caroline to Kingsgate and one from Caroline to Monchy as discussed in Chapter 4. The estimate included fuel volumes of 1.4 percent to be purchased from southern Canadian supply sources and valued at average Alberta netbacks according to the two price case projections.

The condensate was assumed to be shipped via a new condensate pipeline from the Mackenzie Delta to Norman Wells where it would supplement prospective declining volumes in the existing Interprovincial Pipe Line (NW) Ltd. Norman Wells pipeline. Total incremental costs were estimated as $286 million (PV$).

The Applicants' benefit-cost analysis included a number of adjustments to commercial market values where it was thought that those values did not reflect the true value of the resource to Canada.

The Applicants assumed that development-related jobs represented temporary employment and that operating jobs represented permanent employment. In addition, a category of semi-permanent jobs was identified to reflect the lengthy duration of the development of additional natural gas fields in the Delta. The Applicants assumed that the "social opportunity cost of labour" ("SOCL")[2] was 90 percent of the private wage bill for development, 70 percent of the operating labour cost, and 80 percent of the labour costs of developing future natural gas fields in the Delta. These adjustments

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1 *Social Supply Costs* are the sum of capital and operating costs per unit of production, exclusive of royalties, taxes, subsidies, or incentive payments, discounted at the estimated social opportunity cost of capital in Canada.

2 The *SOCL* is the value attached to the activity in which workers would have been engaged in the absence of the project. In general, the SOCL is different from the financial cost of labour because of taxes, unemployment insurance payments, and the level of unemployment. The SOCL varies according to whether jobs are permanent or temporary. If the project involved the transfer of previously employed workers, then the SOCL would be the social value of the associated lost output. This can be approximated by the gross-of-tax wage of the vacated position. For previously unemployed workers hired for the project, the net-of-tax wage rate, which is the amount seen by the workers and which enticed those workers to offer their services, less their net-of-tax unemployment benefits, is the maximum value of the SOCL. This would be a maximum value because it is possible that the workers in question would have accepted a job at a lower wage rate, if one had been offered, indicating that this was the opportunity cost of their time. In addition, the economic impact of creating temporary jobs differs significantly from that of creating permanent jobs. The creation of temporary jobs might entice into the labour market workers who, once the jobs terminate, would be eligible for unemployment benefits they would not have enjoyed in the absence of the project. These additional unemployment insurance benefits are a social cost of the employment of these workers. The creation of permanent jobs, on the other hand, would generally reduce the number of temporary workers and thus the magnitude of future unemployment benefits. Thus the SOCL for permanent jobs would be less than the SOCL for temporary jobs. Whether a job is temporary or permanent depends on the duration of the employment.

were based on labour market information available in 1984. The Applicants noted that although the decline in unemployment rates since 1984 would compress the adjustment, the high unemployment in northern regions would tend to maintain it at the higher level. The resultant reduction in labour costs was $158 million (PV$).

In a social benefit-cost analysis, only actual costs and benefits to Canada are included; the means of paying for or receiving them are not. These payments are transfers between receivers and providers of goods and services rather than actual costs or benefits. To include both costs and transfers would be double counting. Therefore, the Applicants excluded property taxes, provincial and federal income taxes and any royalty payments as these items were not considered to represent the cost of government services accorded the project, but rather transfer payments[1]. In addition, duty flows to the federal government from the import costs associated with the project were estimated by the Applicants to be $39 million (PV$) and were subtracted from the costs.

The project would generate U.S. currency flows for Canada. The Applicants adopted a premium of 5 percent for foreign exchange[2] which was applied to gross border revenues less imports and net foreign financing flows. The social value of foreign exchange was estimated as $396 million (PV$) and $545 million (PV$) in the low and high price cases, respectively.

The Applicants indicated that environmental costs were included in their analyses, but noted that it is difficult to separate the costs for environmental protection from the costs resulting from the use of good engineering practice in the design and construction of a pipeline or production facilities. The pipeline cost estimates included $180 million (1988$) for environmental protection and restoration. In addition, the Applicants stated that the 21 percent contingency for unanticipated costs included in the cost estimate was intended, in part, to cover such items. The Applicants noted that they have not attempted to assess the environmental and socio-economic impacts of the hypothetical pipeline as these would be addressed in any future facilities application under Part III of the NEB Act.

The Applicants estimated the user costs[3] associated with the applied-for exports based on the supply cost estimates, incremental conventional reserves, and demand projections included in the September 1988 Report with some modifications. The September 1988 Report provides unit costs of reserve additions in Western Canada but it does not provide costs for frontier reserves in the Mackenzie Delta/Beaufort Sea region. For gas from these frontier reserves, the Applicants modified the Board's supply cost curve to include 9 EJ (8,550 Tbtu) of Mackenzie Delta gas at $2.33/GJ ($2.45/MMbtu) (1988$) delivered to Alberta and an additional 10 EJ (9,500 Tbtu) of Mackenzie Delta/Beaufort Sea gas valued at $2.51/GJ ($2.64/MMbtu) (1988$) in the low price case and at $2.57/GJ ($2.71/MMbtu) (1988$) in the high price case. The Applicants' analysis assigned the values of $4.78/GJ ($5.03/MMbtu) (1988$) and $6.66/GJ ($7.01/MMbtu) (1988$) in the low and high price cases respectively for all other frontier reserves.

To do their user cost calculation, the Applicants' "base case" used the domestic demand projections for natural gas included in the September 1988 Report and added currently authorized natural gas exports. The "with-export case" consists of their project volumes plus their "base case" volumes. The user cost is calculated as the difference in present worth cost between the "base case" and the "with-export case", less the difference in direct production cost. Because licensed natural gas export volumes in effect at the time of the analysis drop off sharply after 1994, this methodology results in a "base case" demand estimate in which exports of natural gas fall below 500 PJ (475 Tbtu) by 1998 and continue declining to 121 PJ (115 Tbtu) by 2004.

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1 The recovery of costs underlying these transfers are implicitly accounted for in the discount rate, which provides a rate of return to all of society's capital committed to the project.

2 Some argue that a foreign exchange adjustment to costs and benefits denominated in non-Canadian currencies is required because tariffs, subsidies and duties reduce the market-determined value of foreign exchange below what it would be without these items. Thus it is argued that any inflow of foreign exchange resulting from increased exports provides a benefit if it causes an appreciation of the exchange rate thus offsetting the distortionary impact of tariffs, subsidies and duties.

3 New exports necessitate the development of more expensive gas reserves to meet domestic and other export demand sooner than would be the case in the absence of the new exports. The associated increase in the cost of meeting these other demands is called the *user cost* of the new exports.

The Applicants' analysis was undertaken at 6, 8 and 10 percent real discount rates.

The Applicants concluded that benefits ranging from $1.3 billion (PV$) in the low price case to more than $2.5 billion (PV$) in the high price case based on the projections in the September 1988 Report, clearly make the proposed project a desirable one from a Canadian public interest perspective.

The Dene/Metis noted that, in their view, there was not enough evidence before the Board in the benefit-cost analysis to determine whether the issuance of the export licences would be in the public interest.

The Dene/Metis stated that the Applicants' benefit-cost analysis excluded socio-economic considerations such as the impact on cultures, education and public health. Furthermore, the Dene/Metis stated that the analysis did not include any adjustment for cumulative regional impacts. It noted that not only would there be impacts associated with these particular applications but the construction of any pipeline would result in subsequent additional oil and gas developments and further impacts. The Dene/Metis maintained that a complete analysis required all of these impacts to be included. The Dene/Metis also questioned whether the Applicants' analysis included a sufficient amount for environmental costs.

In summary, the Dene/Metis stated that the global benefit-cost analysis approach adopted by the Applicants might be appropriate for the expansion of southern pipelines and exports from the south, but it was not appropriate for frontier regions because the benefit-cost approach ignores the cumulative regional impacts. In the South such impacts might be insignificant but in the North the impacts could be significant and could require mitigative measures which still might not eliminate the potentially negative impacts. The Dene/Metis maintained that there might be net benefits to Canada but these should be weighed against the potential costs to be borne in the region and, in particular, to be borne by the Dene/Metis.

Views of the Board

The Board usually evaluates an applicant's benefit-cost analysis by preparing its own assessment to reflect differences in judgement about certain assumptions. The results of the Board's benefit-cost analysis of the proposed exports are shown in Table 7-2.

Table 7-2

Proposed Mackenzie Delta Export
NEB Benefit-Cost Analysis

(billions of 1988$, discounted at 8%)

	Low World Oil Price	**High World Oil Price**
Export Revenue	9.3	12.9
Condensate Revenue	0.7	1.1
Less:		
Production Costs	2.5	2.5
Gas Transmission Costs	4.1	4.2
Condensate Transportation Costs	0.3	0.3
Equals:		
Net Direct Benefits	**3.1**	**7.0**
Plus Indirect Adjustments[1]:		
Labour Externality	0.2	0.2
User Costs	-2.2	-5.9
Net Indirect Adjustments	-2.0	-5.7
Equals:		
Net Social Benefits	**1.1**	**1.3**
Benefit/Cost Ratio	**1.13**	**1.10**

1 The indirect adjustments include an amount of $39 million (PV$) for net duties.

As noted above, the Applicants' projections for their average natural gas export price were based on data contained in the September 1988 Report. These prices were projected to reach $3.77/GJ ($3.97/MMbtu) (1988$) in the low price case and $5.12/GJ ($5.39/MMbtu) (1988$) in the high price case by 2005. Thereafter, the Applicants have assumed that the average price falls to $3.59/GJ ($3.78/MMbtu) and $4.91/GJ ($5.17/MMbtu) by 2016 in the low and high price cases respectively. In its analysis, the Board has used similar prices to the Applicants' to 2005. Thereafter, the Board's prices continue to grow consistent with the increasing marginal costs of reserves required to meet the Board's demand projections. These

demand projections are higher than the Applicants' because they include a projection of exports. Table 7-2 shows that the Board's assumptions result in a higher projection of export revenues than those included in the Applicants' analysis. The Applicants' analysis, as noted above, includes an average fuel loss of 5 percent for gas delivered to Niagara. Since a benefit-cost analysis is based on incremental benefits and costs, the Board believes that a marginal fuel use of 10 percent should be used. Assuming the Applicants' estimate of 1.1 percent fuel loss for exports at Kingsgate and Monchy and the above 10 percent for exports at Niagara and using projections for an Alberta price consistent with the low and high world oil price scenarios, the Board has estimated fuel costs as $154 million (PV$) and $219 million (PV$) in the low and high price cases, respectively.

As discussed above, the Applicants' analysis includes a foreign exchange adjustment valued at $396 million (PV$) in the low price case and $545 million (PV$) in the high price case. The foreign exchange adjustment is only justified if it is believed that tariffs, subsidies and duties are in fact distortionary in the sense that they introduce a wedge between the foreign and domestically denominated prices generated in a properly functioning market. However, it is equally arguable that they were introduced to correct past market imperfections. Furthermore, the foreign exchange adjustment implies that tariffs, subsidies and duties will continue to exist throughout the analysis period. The validity of these assumptions is not at all clear given the Free Trade Agreement with the United States and the potential for the removal of trade restrictions with other countries pursuant to GATT[1] negotiations. The Board is not convinced that adjusting foreign exchange earnings to reflect a social premium is necessarily justified. Therefore, no adjustment has been included in the Board's analysis.

Socio-economic impacts, such as the impacts on culture and life styles, are generally very difficult to quantify. One socio-economic impact explicitly quantified in the Applicants' analysis was a benefit from northern job creation which was included in the labour cost adjustment (SOCL discussed above). In addition, the Applicants' pipeline cost estimate includes a 21 percent contingency which is intended, in part, to cover environmental and socio-economic costs associated with the hypothetical pipeline. However, it is not clear what portion of this contingency related to these costs, or was a pure reserve for unexpected pipeline engineering and construction cost escalation. The Board used the Applicants' pipeline cost estimate in its analysis and performed sensitivity tests about this estimate.

The Board notes that during the examination of any pipeline application, there would be a detailed review of the plans designed to enhance benefits and mitigate negative impacts for groups such as the Dene/Metis. Moreover, since the Applicants' plans for development and production of the gas fields, as well as any pipeline proposal would be at a more advanced stage at that time, there may be more information available which would help to quantify socio-economic, infrastructure and environmental impacts that might be associated with production activities and pipeline construction and operation. To the extent that these can be quantified, they would be included in the benefit-cost analysis of that proposed pipeline.

The Board does not agree that the methodology used by the Applicants in calculating user costs is appropriate. In the Board's view, the Applicants' forecast of export demand in the absence of the proposed exports understates the exports that are likely to flow during the forecast period. Indeed, the Applicants' forecast assumes that pipeline facilities would be under-utilized as existing licences expire and that alternative export market opportunities for Canadian natural gas would not exist.

In the Board's view, a further undesirable aspect of using only licensed exports for the demand forecast would be the potential for unequal treatment of export applicants; i.e. two license applicants with the same volumes and contractual pricing arrangements would be evaluated differently if it happened that the level of licensed exports were different at the time each application was received.

User costs arise because increased production from existing reservoirs accelerates the time frame in which higher cost reservoirs must be exploited. Thus, user costs are a function of the expected gas production profile over time and bear no direct relation to the level of licensed exports, because what is licensed now is not necessarily what would reasonably be expected to flow in the future. In the

1 General Agreement on Tariffs and Trade

Board's view, in the context of a market-oriented export policy environment, the correct approach is to use a reasonable projection of export demand in the absence of the applied-for exports and, as with other components of the analysis, to conduct tests of the sensitivity of the estimates of user costs to lower or higher values of future exports.

In justifying their use of licensed exports, the Applicants stated that they did not believe that the costs and benefits of their proposal should be influenced, in the context of the user cost calculation, by yet to be approved exports; hence, in their view only domestic demand and authorized exports should be considered for this purpose. Furthermore, the Applicants referred to the Board's letter of 19 December 1984 on benefit-cost procedure. The intention of this letter was to standardize the assumptions to be used for the benefit-cost analyses of certain competing facilities applications at that time; it was not intended to be a directive from the Board on methodology to be used in future facility or export applications. Moreover, in the letter it is stated that "assumptions must be made with respect to future domestic and export requirements for Canadian natural gas with (Incremental Case) and without (Base Case) the incremental natural gas sales." In the Board's view, given the current policy context, it is appropriate to consider "export requirements" to mean a reasonable projection of total ongoing natural gas exports.

In estimating user costs, the Board used projections of domestic and export demand contained in the low and high cases of the September 1988 Report. The applied-for export volumes were then deducted from these projections to determine the production profile in the absence of the export. The total incremental production costs attributable to the applied-for export were then calculated as:

(1) the net present value of the total production costs of all projected production with the proposed export; minus

(2) the net present value of the total production costs of all projected production without the proposed export.

The total incremental production costs consist of the direct cost of the exports and the associated user costs. Therefore, subtracting the Applicants' own direct production costs from total incremental production costs yields the estimated user costs attributable to the applied-for export. The Board's methodology yielded higher user costs than those estimated by the Applicants, because cumulative production is greater using an estimate of expected export flows rather than the estimate of licensed export flows.

In deriving the unit supply costs used to estimate incremental production costs, the Board assumes that industry will respond to the challenge of lower oil prices by reducing costs through technological developments and other cost cutting means. Thus, the Board's estimated unit supply costs are lower in the low price case than in the high price case. In its "base case" benefit-cost analyses (both the low and high price cases) the Board has used the Applicants' estimates of the costs of their gas, \$2.33/GJ (\$2.45/MMbtu) (1988\$), in other words, there was no differentiation in the cost of the Applicants' gas under the two price cases. For other Delta gas, the Board has used the estimated volume and unit supply costs discussed in Chapter 2 for the low price case. Consistent with the September 1988 Report methodology, the unit supply costs of the other onshore and offshore reserves shown in Table 2-8 were increased by 20 percent for the high price case.

The Board's analysis assumes that Mackenzie Delta gas would be produced even if the proposed exports were not approved. In the "without export" case this frontier gas is assumed to commence production in 2004 and 1999 for the low and high price cases respectively. In these years the social cost of the frontier gas, \$2.33/GJ (\$2.45/MMbtu) assuming a twenty-year recovery of pipeline cost, is competitive with the social cost of the marginal southern Canadian supply source. The impact of the proposed exports would be to advance the construction of a northern pipeline so that this gas could begin production in 1997. Thus under the export case these facilities are "prebuilt" and the associated costs are recovered from the proposed exports. Once these exports terminate, the pipeline facilities would be available to meet other demand. The capacity of this pipeline is assumed to be 487 PJ (463 Tbtu) per year in both the "with" and "without export" cases.

Table 7-3

Proposed Mackenzie Delta Export Sensitivity Analysis of Net Benefits

(billions of 1988$, discounted at 8% real unless otherwise indicated)

	Net Benefits Low World Oil Price	Net Benefits High World Oil Price
Social Discount Rate		
6%	2.0	1.7
8% ("Base Case")	1.1	1.3
10%	0.5	0.9
Pipeline Costs		
30% Capital Cost Increase	0.7	1.2
30% Capital Cost Decrease	1.5	1.4
Operating Cost Increase	0.6	0.8
Proposed Export Points		
Including Incremental Facility Expansions to Niagara	1.0	1.2
Assuming all Gas Exported at Kingsgate and Monchy	1.0	1.2
User Costs - Level Of Exports		
Pipeline Capacity	1.2	2.7
Exports of 1.8 EJ Per Year	0.8	0.7
Exports of 2.0 EJ Per Year	0.6	0.2
User Costs - Unit Supply Cost		
20% Increase in WCSB[1] Additions Supply Costs	0.2	0.7
Higher Backstop Values	1.0	0.9
Gas Export Prices		
Applicants' Prices	0.2	-0.2
Prices increased by 10%	2.0	2.5
Prices decreased by 10%	0.2	0.0

1 Western Canada Sedimentary Basin

The Board has undertaken a number of sensitivity analyses related to the social discount rate, pipeline costs, proposed export points, user costs, and gas export prices. The results are summarized in Table 7-3 and are discussed below.

The Board has tested the sensitivity of the net benefits to real social discount rates of 6, 8 and 10 percent. The costs associated with any new pipeline facilities occur during the initial years of the analysis while the gas export revenues are earned in later years. As the discount rate falls, the present value of the revenues increases by relatively more than the present value of the pipeline facilities costs. Thus net benefits increase as the discount rate is reduced. User costs are also incurred in the latter part of the analysis period and thus they tend to offset the increases in the present value of revenues as the discount rate falls. Since the user costs are relatively higher in the high price case, this offsetting means that the spread of net benefits is less under the high price case than under the low.

As discussed in Chapter 4, there is some uncertainty about the capital and operating costs of hypothetical pipelines from the Delta to Caroline and from Caroline to Kingsgate and Monchy. To test the sensitivity of the estimated net benefits to changes in pipeline construction costs, the Board used a range of plus or minus 30 percent for capital costs. In addition, holding capital costs at base case values, annual operating costs were increased from $66 million (1988$) to $147 million (1988$) per year for the pipeline from the Delta to Caroline and from $6.7 million (1988$) per year to $20 million (1988$) per year for the pipeline from Caroline to Kingsgate and Monchy. As shown in Table 7-3, a 30 percent increase in the costs of constructing a pipeline from the Delta to Caroline would still yield net benefits to Canada, in both the low and high price cases. However, the net benefits would be reduced to $0.7 billion (PV$) and to $1.2 billion (PV$) in the low and high price cases respectively. A 30 percent decrease in pipeline construction costs would increase net benefits to $1.5 billion (PV$) and $1.4 billion (PV$) in the low and high cases. Increases in operating cost for the pipeline would reduce net benefits to $0.6 billion (PV$) and $0.8 billion (PV$) in the low and high cases respectively.

Although the Applicants' analysis assumed that an additional 41 PJ (39 Tbtu) per year of natural gas would be exported at Niagara, it did not include any incremental capital costs associated with expanding TransCanada PipeLines Limited's

("TCPL's") system to Niagara. The Board believes that, if the assumption is that solely on account of this project, incremental gas is to be exported at Niagara, an allowance for pipeline facilities should be included in the analysis. The Board has conducted a sensitivity analysis of including an advancement over the applied-for twenty year licence term of approximately 170 km (106 mi) of loop and 40 MW (53,640 hp) of compression for TCPL totalling approximately $212 million (1988$) and a further $38 million (1988$) on Foothills/NOVA from Caroline to Empress and $19 million (1988$) on Union. It was assumed that the overall fuel requirements to transport gas from Caroline to Niagara would be 10 percent. These assumptions result in a slight reduction of the net benefits to $1.0 billion (PV$) and $1.2 billion (PV$) in the low and high price cases, respectively as shown in Table 7-3.

Alternatively it could be assumed that the hypothetical pipeline provides sufficient capacity so that all of the gas could be exported at Kingsgate and Monchy. In this case, there would be no requirement for expansions of TCPL, Foothills, NOVA, or Union as discussed above. Export revenues, however, would fall from $9.3 billion (PV$) to $9.1 billion (PV$) and from $12.9 billion (PV$) to $12.7 billion (PV$) in the low and high price cases respectively. The cost of transportation fuel from Caroline to Monchy and Kingsgate would be reduced by $61 million (PV$) to $94 million (PV$) in the low case and by $86 million (PV$) to $133 million (PV$) in the high case. This would result in a slight decrease in net benefits of $21 million (PV$) and $9 million (PV$) in the low and high price cases versus the previous case which included the costs of incremental facilities to transport the gas to Niagara. The impact of this assumption on the net benefits of the project relative to the base cases is a reduction in these net benefits of $135 million (PV$) in the low price case and $123 million (PV$) in the high price case.

The Board conducted analyses to test the sensitivity of the net benefits to the choice of the gas production profile used in the user cost calculation. For the first sensitivity, it was assumed that in the "without-project" case exports would fill existing pipeline capacity as domestic demand increases. In this scenario exports decrease but by less than they would using only "authorized exports". The Applicants' exports were treated as incremental to these volumes. User costs under the low price case fall from $2.2 billion (PV$) to $2.1 billion (PV$). Under the high price case, user costs fall from $5.9 billion (PV$) to $4.5 billion (PV$). Net benefits increase as shown in Table 7-3.

Further sensitivities of net benefits to the choice of the gas production profile were also performed. The projection of export volumes was increased to 1.8 EJ (1,710 Tbtu) and 2.0 EJ (1,900 Tbtu) per year for both the low and high price cases. In both the September 1988 Report and the base case benefit-cost analyses shown in Table 7-2, the projection of export volumes were 1.5 EJ (1,425 Tbtu) per year. The impact of the increased export projections was an increase in the user costs. Under the export projection of 1.8 EJ (1,710 Tbtu), user costs increased to $2.5 billion (PV$) and $6.5 billion (PV$) in the low and high price cases. Under the export projection of 2.0 EJ (1,900 Tbtu), user costs increased to $2.7 billion (PV$) and $7.0 billion (PV$) in the low and high price cases respectively. Increases in the user cost resulted from an accelerated depletion of the various supply sources since the total gas demand was greater, all other things being equal. In the low and the high price cases, gas from backstop reserves was required 2 years earlier and 3 years earlier with additional annual exports of 300 PJ (285 Tbtu) and 500 PJ (475 Tbtu) respectively. As shown in Table 7-3, an increase in projected exports reduces the net benefits.

The sensitivity of the net benefits to a 20 percent increase in the Board's estimates of supply costs of both WCSB reserves additions and gas from the frontier regions, was also tested. In this case, the supply costs of the established reserves and the backstop value[1] were kept unchanged from the base case levels of $0.71/GJ ($0.75/MMbtu) and $4.78/GJ ($5.03/MMbtu) and $0.78/GJ ($0.82/MMbtu) and $6.66/GJ ($7.01/MMbtu) (1988$), in the low and high price cases, respectively. This test resulted in an increase of $883 million (PV$) and $625 million (PV$) in the total of direct production and user costs associated with the export in the low and high price cases,

1 The *backstop* value reflects the value of the most easily substitutable energy source which is expected to be available in unlimited quantities in the future. The backstop in the 1988 Supply/Demand Report is light fuel oil in the low world oil price case and gas either from the frontier regions or from alternative sources such as coal gasification in the high world oil price case.

respectively. As shown in Table 7-3, an increase of 20 percent in the supply costs, holding the backstop value and the cost of established reserves constant, would reduce the net benefits to $0.2 billion (PV$) and to $0.7 billion (PV$) in the low and high price cases, respectively.

Because of the significance of the user cost and the influence of the backstop value, the Board has assessed the impact of changes in the backstop value on the estimated user costs and on the project's net benefits. In the low case, the backstop value was increased to $5.00/GJ ($5.26/MMbtu) from $4.78/GJ ($5.03/MMbtu) (1988$). This increased the total incremental gas costs (production and user costs) by $0.2 billion (PV$) and reduced the net benefits to $1.0 billion (PV$). In the high case, the backstop value was increased to $7.00/GJ ($7.37/MMbtu) from $6.66/GJ ($7.01/MMbtu) (1988$). This generated an increase of $0.4 billion in total incremental gas costs (production and user costs) and reduced the net benefits to $0.9 billion (PV$).

The Board also has examined the sensitivity of the net benefits of the proposed exports to changes in export prices. Several alternatives for export prices were considered. For the first price sensitivity, the Board used the Applicants' export prices, which were lower than the Board's after 2005, to evaluate the export revenues and fuel from Caroline to the U.S. border. The impact is a reduction in gas export revenues from $9.3 billion (PV$) to $8.4 billion (PV$) in the low price case and from $12.9 billion (PV$) to $11.3 billion (PV$) in the high price case. The fuel from Caroline to the U.S. border was reduced by $16.5 million (PV$) and $27.5 million (PV$) in the low and high price cases, respectively. This sensitivity would reduce the benefits to $0.2 (PV$) and -$0.2 billion (PV$) in the low and high price cases, respectively, again confirming the importance of the revenue estimates to the project viability evaluation.

The Board has also analyzed the impact of an increase of 10 percent and a decrease of 10 percent in the average export price. Under the increase of 10 percent net benefits increase to $2.0 billion (PV$) and $2.5 billion (PV$) in the low and high price cases respectively. Under the 10 percent decrease in prices net benefits are reduced significantly, falling to $0.2 billion (PV$) in the low price case and being eliminated in the high price case.

In conclusion the Board finds that the proposed exports would likely provide net benefits under most reasonable assumptions. Two of the major uncertainties in the analyses, at this time, are the lack of export sales contracts specifying export prices and the absence of detailed information on the required northern pipeline. However, before any exports would flow, a pipeline would have to be constructed. The required pipeline would be the subject of a future hearing under Part III of the NEB Act. The Board's review, at that stage, would include a benefit-cost analysis of the proposed facilities, taking into account all relevant project associated factors as understood at that time including the prices specified in the export sales contracts.

Northern Issues

8.1 Dene/Metis Land Claim

Recent History

In the federal government's White Paper of 1969[1], the government was prepared to resolve outstanding "lawful obligations" so treaties could be "equitably ended", and the special status of Indians could be terminated.

In August 1973, the Minister of Indian Affairs and Northern Development, issued a statement describing the government's positions for remedying two basic problems arising from the initiation of treaties. The first position concerned the government's lawful obligation to Indian People arising from grievances concerning the non-fulfillment of existing Indian treaties, the administration of reserve lands and other assets under the *Indian Act*, and other formal agreements. That position was referred to as "specific" claims policy.

The second position concerned the continuing use and occupancy of traditional lands - where no treaty, formal agreement or specific legislation had ever been signed or passed. The government recognized the native right to the land resource (traditional use) and to the need for settlement (occupancy). As continuing use and occupancy could include such items as:

(i) protection of hunting, fishing, and trapping;

(ii) land title;

(iii) money; or,

(iv) other rights and benefits, in exchange for a release of the general and undefined Native title;

the position came to be referred to as "comprehensive" claims.

Comprehensive Native Claims North of 60°

The Western Arctic Claims Agreement, i.e. the Inuvialuit Final Agreement of 1984, is the first and, so far the only settlement concluded under the 1973 federal comprehensive claims policy. The Agreement extinguishes the aboriginal claim of the Inuvialuit of the Western Arctic in exchange for their ownership of certain lands; hunting, fishing, and trapping rights; and 45 million dollars. It also provides for the protection of social and cultural rights. The Agreement was negotiated and signed by the Committee for Original Peoples' Entitlement representing the Inuvialuit and by the Government of Canada.

Three other comprehensive claims north of the 60th parallel are now under negotiations (See Map). Those claims were put forward by:

(i) the Council for Yukon Indians ("CYI");

(ii) the Dene Nation and Metis Association of the Northwest Territories ("Dene/Metis"); and

(iii) the Tungavik Federation of Nunavut (representing the Inuit of the Central and Eastern Arctic).

When a land claim is accepted for negotiation, the government requires that the negotiation process and settlement formula be complete, so any land claim settlement will be final. The negotiations are designed to deal with matters arising from the notion of aboriginal land rights such as, lands, cash compensation, wildlife rights, and may include self-government institutions on a local basis.

1 Department of Indian Affairs and Northern Development. 1969. *Statement of the Government of Canada on Indian Policy*. Ottawa:DIAND

The 1973 policy statement indicated two new approaches with respect to comprehensive claims. First, the federal government was prepared to accept land claims based on traditional use and occupancy. Second, the federal government was willing to negotiate settlements of such claims although any acceptance of such a claim would not be an admission of legal liability.

The Dene/Metis Land Claim

In 1985, the Dene/Metis filed with the government, "The Dene/Metis Comprehensive Land Claim". Since then, the negotiators on both sides have worked upon a number of sub-agreements covering various aspects of the claim issues. Those sub-agreements were initialled as agreement was reached, and the summation of those was incorporated in the Dene/Metis Agreement-in-Principle ("AIP") signed in September, 1988.

That AIP has set down the framework of conditions which must be followed in the formulation of a Dene/Metis Final Agreement.

The claim area (see Map), covers 1 165 495 km^2 (450,000 square miles). Throughout that area, the Dene/Metis have exclusive right to hunt and fish, subject to certain wildlife management restrictions.

A second tier of land rights includes exclusive surface-rights ownership. The Dene/Metis may select an amount of land, not yet specified, which may be of significance to traditional hunting patterns. Ownership of those lands would require that the Dene/Metis allow other parties, who own the sub-surface rights, to enter and use the surface lands based upon a lease or rental system.

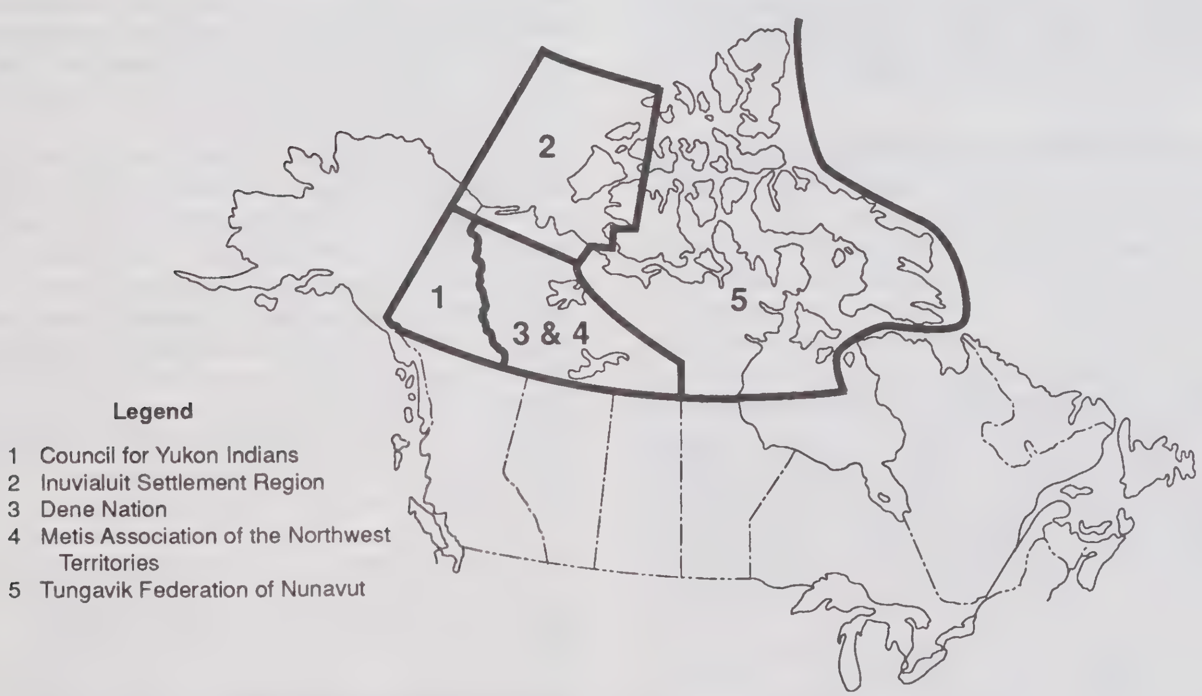
A third tier of ownership is totally exclusive. The Dene/Metis, through subsequent negotiation, will be allowed to select a limited amount of land around each community. The amount of land would vary with negotiation and would include ownership of surface and subsurface rights. By that form of ownership, the Dene/Metis would be in a position to:

(i) totally protect cultural features;

(ii) establish areas for community growth; and

(iii) develop the natural resources in a commercial or industrial fashion.

Comprehensive Land Claims in Canada North of 60° [1]



1 Apart from the Inuvialuit Settlement Region, areas represent only approximate boundaries of the various interests.

A fourth tier includes accessing an economic interest in the resources of the entire 1 165 495 km^2 (450,000 square miles). The Dene/Metis would negotiate a specific interest in the Norman Wells oil reserves and development and, as well, would have an opportunity to negotiate a blanket interest, or overall percentage, of natural resource development revenue.

The AIP contains 35 other sub-agreements, each of which must be negotiated to mutual acceptance before a Final Agreement can be achieved. The Dene/Metis expect that the Final Agreement will be reached by 1991.

Meanwhile, an Interim Protection Agreement is in place which will freeze land use on lands as they are selected by the Dene/Metis during the negotiation process.

Dene/Metis Evidence

In the evidence placed before the Board, the Dene/Metis stated that they are currently in the midst of negotiations, working from the 36 sub-agreements toward a Final Agreement.

The Dene/Metis made the point that for past projects there was insufficient lead time for them to make their preparations for taking advantage of the opportunities which a northern project might provide. At present, their time and resources are fully extended in their comprehensive claim negotiation.

To the time of this hearing, land selection has been concentrated in the Delta region, and approximately 3,900 square miles have been selected. There remain four other Dene/Metis regions in which land selection has yet to be negotiated.

Without completion of their land claim, the Dene/Metis will not know which lands they will own, nor in which of the four categories of ownership those lands will fall. With the Final Agreement, they feel there would be included sufficient cash payments to fund the establishment of businesses to meet the new opportunities. The Final Agreement will also be the key to the creation of Dene/Metis institutions for land-use and resource planning and management.

The Dene/Metis expressed their concern that approval of the export application would lead quickly to an application for a pipeline. With their resources already fully occupied, they would be unable to adequately negotiate their Final Agreement, and consider it to be unfair to add the additional burden of a pipeline review.

The Dene/Metis requested that no commitments be made with respect to the development of Mackenzie Delta gas which could prejudice the settlement of their comprehensive claim. Two years from the signing of the AIP in September 1988, has been set as the period required to reach that Final Agreement. In that respect, the Dene/Metis requested that licences for the gas export not be given at this time, or at least be conditioned to delay implementation. A delay of many years was not anticipated, but rather of one or two years.

In examining potential buyers of the gas to be exported, the Dene/Metis explored the possible consequences of a delay in the approval of the gas export applications. The buyers were looking to secure gas for 1996, and felt that delays beyond that would create some uncertainty in their planning. Foothills felt the market would still be there. The Inuvialuit and the GNWT felt there was no need to delay or condition any licences for export.

In their final argument, the Applicants addressed the Dene/Metis suggestion for a licence condition delaying the approval until native land claims have been settled. The Applicants indicated that the evidence showed such a delay would cause considerable uncertainty with respect to project timing, and difficulty in marketing Delta gas.

The Dene/Metis reiterated their fear that approval of a gas export licence now would prejudice their comprehensive claim negotiations. They described how Dene/Metis management organizations will not come into force until implementation of the Final Agreement, how capital to fund development projects will be available only upon signing the Final Agreement, and how other compensation and benefits will accrue only upon completing the Final Agreement. The status of the Dene/Metis land selection and protection was outlined, and the finality of that selection was emphasized.

The negotiations to achieve those benefits are now underway, and it was described as a painstaking exercise. The Dene/Metis are being asked to make decisions they will have to live with for centuries. The Dene/Metis expressed the high stakes for them, the high level of their priority, and how

outside pressures could disrupt and prolong the negotiation process. The granting of an export licence at this time, they felt, could jeopardize both land claims and self-government negotiation.

The Dene/Metis, therefore, requested a relatively short postponement of the export licences. They saw little risk that markets would be lost through a delay of two to four years.

Views of the Board

The Dene/Metis have requested that any facilities application be delayed until their land claim negotiations are settled, either by denying this application or by means of a condition to the licence.

The Board understands that the Dene/Metis have approximately two years during which to complete their negotiations to develop the clauses of their AIP into a Final Agreement. Organizing their infrastructures and policies will follow after that.

The Board notes that there is already in place an Interim Agreement that will freeze land-use upon lands selected as that occurs. To some extent that has been done, and land selection is actively being negotiated.

The major concerns of the Dene/Metis revolve around potential problems associated with an application, to construct the facilities to move natural gas volumes to market, before their claims negotiations are finalized. In considering the timing of a facilities application, the Board notes the Dene/Metis wish to have their negotiations completed before the filing of the application and not just prior to construction.

It is clear that an early facilities application could further stretch limited Dene/Metis resources. That could also preclude sufficient lead time for the Dene/Metis to become organized to take best advantage of business and labour opportunities arising from pipeline construction.

The Board recognizes the importance of resolving native land claims. The applications under consideration are, however, solely for licences to export natural gas from the Delta region, and not for the approval of pipeline facilities. On the basis of the evidence before it, the Board is not convinced that approval of gas export licences would prejudice the settlement of the Dene/Metis claim. An approval of export licences does not mean that consideration of a facilities application would follow shortly, thereby straining the resources of the Dene/Metis. Considerable preparatory work, including detailed discussions with all Northerners, would be required before an application.

On balancing the desires of the Dene/Metis, the Applicants and a strong expression of support from Northerners representing the majority of those concerned, the Board finds it neither necessary nor desirable to delay its decision with respect to the export applications, nor to add a condition delaying the implementation of any licences to export gas.

8.2 Benefits to Northerners

Beaufort Mackenzie Development Impact Zone Society

The Beaufort Mackenzie Development Impact Zone Society ("DIZ Society") supported the development of hydrocarbons from the Mackenzie Delta/ Beaufort Sea area. However, its support was conditional upon the provision of employment and business opportunities for the North, and environmental protection.

The Society saw a need for ongoing training. It recommended that communities be kept well informed during the development process, and confirmed that the Society would be a good medium for the exchange of information.

Canadians for Responsible Northern Development

The CRND presented its views concerning training programs. It suggested that an apprentice-journeyman program could be feasible and beneficial in the North.

It also stated that early planning of development should be undertaken. It is concerned that Northern people might not benefit from the employment opportunities if there were not adequate planning. The CRND mentioned that during previous development Fort McMurray was left with infrastructure that was not needed once the project was over. Therefore, it had to pay for those facilities. The CRND would like to see measures taken now to ensure that this does not happen in the Delta.

Council for Yukon Indians

Several of the Yukon Indian Nations have unresolved transboundary claims which cover territory in the Mackenzie Valley watershed. The CYI believes that the export licences should not be issued until both the Yukon Indians and Dene/Metis land claims are settled. Therefore, it fully supports the Dene/Metis' position.

The CYI affirmed that it was strongly opposed to any development on the Yukon North Slope.

Dene/Metis Negotiations Secretariat

The Dene/Metis's concerns relating to the status of its land claim settlement and its ability to benefit from developments associated with the proposed exports were discussed in Section 8.1. In addition to these concerns, the Dene/Metis noted that the Dene/Metis will need training to qualify for employment. Because the training process was very late in the Norman Wells project and as a consequence was much less effective than it could have been , they have recommended that a planning process and implementation of training start well in advance of the construction of a pipeline.

Furthermore, the Dene/Metis was very concerned about the potential for cumulative regional impacts. According to the Dene/Metis, there will be regional impacts associated with these export applications but more impacts will result as a pipeline is built and more exploration takes place in the region and new transportation systems are developed. The Dene/Metis was concerned that the cumulative regional impacts might be sufficiently negative to conclude that the project is not in the public interest.

Northwest Territories Federation of Labour

The Northwest Territories Federation of Labour indicated that if certain conditions were met the issuance of licences to the Applicants would be acceptable. It would like any licences to include conditions related to socio-economic matters such as training, employment, and impacts on communities.

The organization stated that employment of Northerners should be optimized. It noted however, that Northerners cannot compete with experienced workers from the South so they need adequate training to have an equal opportunity. In order to achieve the goal of optimizing employment, assessments of skills available, jobs available, training that is required and skills which are transferable after the development must be undertaken as soon as possible.

The Federation encouraged Northerners to apply for every job, the duties of which they could fulfil. It suggested that training should be partly financed based on a prorated amount of the total development by the Applicants but that planning should be a shared responsibility by governments, native organizations, industry and labour.

According to the Federation the training provided for the Norman Wells project was "too little, too late". Based on the Federation's experience with that project, the organization made several recommendations. The first was the need for a body to co-ordinate and monitor the project. Furthermore, it recommended that a Northern Employment and Training agency be put in place to be responsible for human resources. It also identified a need to define northern residency.

The Federation questioned whether the Federal and Territorial governments are ready for a major development. Its concerns were related to matters that affect working people, such as safety laws and fair wage laws. It believed that those issues should be addressed by these governments before any major development begins.

The Federation also expressed a desire to have energy supply available, at a reasonable price, in the North. However, it was concerned about who would pay for the laterals to make those supplies available to the communities.

Dene/Metis land claims have to be settled in order for the Federation to support these export applications.

Inuvialuit Regional Corporation

As noted in Section 8.1 the IRC was in support of the granting of gas export licences.

The IRC felt that it was important that governments put together new procedures such as aid programs, grant programs, education and training

programs, so the people of the North would benefit from the project through business and employment opportunities.

The IRC stated that infrastructures would have to be developed by government at the community level. It recommended that government and industry should start now to develop means to co-ordinate the economic activity so that the construction activities related to developing and transporting the gas to market do not take place at the same time as the road construction.

A member of the Game Council appeared with the IRC. The Council has the overall responsibility for wildlife and environmental matters and was very concerned about environmental aspects of the export proposal. It stated that the Valdez experience demonstrated the inefficiency of existing measures in the event of a large-scale oil spill disaster. Therefore, it maintained that new contingency plans must be considered.

The IRC believes that Dene/Metis land claims and the Northern Accord will be settled on schedule. It stated that the industry has the responsibility to lobby various levels of governments for the settlement of the land claims.

Northwest Territories Power Corporation

The Corporation generally supported the applications to export natural gas from the Mackenzie Delta region to the United States.

It would, however, like the Board to attach conditions to any licences which might be issued. One of the conditions would be that natural gas be made available to the Corporation and distributors for the generation and distribution of electricity, at a price no greater than the export price excluding the transportation costs.

Another proposed condition was that an assessment of alternatives for powering the pipeline facilities be undertaken and that a preference be given to the electric alternative.

Town of Inuvik

The Town of Inuvik supported and recommended the approval of the applications to export natural gas.

According to the Town of Inuvik, local natural gas demand would not be sufficient to justify the production. Therefore, the region would only benefit if there were early production associated with the exports. It did not believe that exporting natural gas would compromise Canada's capacity to supply its future energy requirements.

The town identified some concerns which should be addressed during the period before the pipeline is built. In particular, the town believed that there must be benefits in terms of business opportunities and employment for local people.

The Town of Inuvik stated that it wanted to be kept well informed and involved and moreover, that it required financial aid for the construction of the necessary infrastructure. It also wanted to have access to natural gas at a reasonable rate.

It feared that hydrocarbon production from the Mackenzie Delta/Beaufort Sea might not begin until far in the future if there were any delay in issuing the licences.

Inuvik Chamber of Commerce

The Inuvik Chamber of Commerce supported the export applications provided that there would be benefits to Northern residents.

The Inuvik Chamber of Commerce stated that Northerners were ready for energy projects. They have political institutions and improved levels of education which would allow them to participate in the development process.

The Chamber of Commerce felt confident that the Dene/Metis land claim and the Northern Accord would be completed within the project schedule.

It suspected that with a project delay, Prudhoe Bay gas could come on stream earlier which they believed could postpone the development of Mackenzie Delta gas for a period of 15 to 20 years.

Hamlet of Fort McPherson

The Hamlet of Fort McPherson stated that it was difficult to separate the export applications from the specific transportation issues. It emphasized the importance of having adequate and timely training programs for native people and stated that no great effort was made in the past by oil

companies to employ native people. The Hamlet suggested that the Applicants should be responsible for training since they know which skills are required for specific jobs. It believed that this responsibility should not be left to governments. Furthermore, the Hamlet suggested that the requirement to provide training be included as a condition of any export licences which might be issued.

Environmental concerns are of prime importance to the Hamlet, because its population relies on a clean environment for its livelihood which is based on hunting. Therefore, it suggested that stringent controls and safety measures should be imposed upon the required transportation system to prevent any kind of environmental disaster.

According to the Hamlet, no export licences should be granted until native people have reached a land settlement which will enable them to participate in development.

Mackenzie Delta/Beaufort Sea Land Use Planning Commission

The land use planning commission is preparing a regional land use plan for the Mackenzie Delta-Beaufort Sea area which will be completed by 1990. It would like their plan to be included in the decision-making process by the Board in subsequent hearings related to pipelines.

Government of the Northwest Territories

The Government of the Northwest Territories supported the applications filed by Esso, Shell and Gulf. The GNWT's support was based on the assessment that there would be benefits for Northerners from the oil and gas development in the Mackenzie Delta/Beaufort Sea area.

It stated that training of Northerners and the identification and development of infrastructure requirements are priorities. Unfortunately, it noted the GNWT cannot finance the additional programs, services and infrastructure required to respond to the impacts of gas and oil development. Some funding arrangements will have to be made and put in place before the commencement of pipeline construction.

The GNWT believes that the Dene/Metis will have reached an agreement with the Federal government by the time the construction starts. It said that the Northern Accord has to be in place before the production starts. The GNWT maintained that it is the Northern Accord and the settled land claims that will give native people and the GNWT the resources to manage development to their benefit.

Even though pipeline issues were not part of this hearing, the GNWT wanted to make their position known in this regard. It stated that it would support a transportation system that would maximize opportunities for employment, training and business development, advantages for northern energy supply and incentives for infrastructure development. The environmental impact which has been and will always be a major concern to Northerners, would also have to be minimal. The GNWT also remains firmly opposed to any development on the North Slope of the Yukon.

Hamlet of Tuktoyaktuk

The Hamlet supported the issuance of export licences with conditions related to the provision of gas to communities in the Western Arctic area. It stated that there are skilled personnel in the North, but there is a need for training, not only for labourers but at the managerial level as well.

The Hamlet hopes that the impact that industry has on their community infrastructure (e.g. roads, harbour and the airport) will be given some consideration. In the past, they noted, they have not received any compensation for the infrastructure costs induced by local development.

City of Yellowknife

The City of Yellowknife recognized that this development proposal would have significant impacts on the Northwest Territories' economy.

The City recommended the approval of the export licences provided that the Applicants would make energy supply available to northern communities and that efforts would be made to maximize business opportunities and employment during the construction and operation phases.

Government of the Yukon Territory

The Government of the Yukon Territory ("YTG") supported the export applications provided that

the following concerns are addressed. The YTG expects that development in the Yukon would provide regional benefits for the people of the Yukon in terms of jobs, training and revenues. The YTG stated that development is necessary to strengthen the Yukon economy but development must be oriented in accordance with the lifestyles of the people in the Territory.

The Government of the Yukon also had concerns related to the environment and the facilities for transportation of the natural gas. Effectively, the YTG remains opposed to any pipeline route which would cross the North Slope of the Yukon, and its support for the export applications depends upon a requirement that diverse routes be explored at a subsequent hearing.

Furthermore, the YTG wants future oil and gas exploration in the Yukon restricted until the Northern Accord is finalized and then only if it does not jeopardize the Yukon land claim agreement.

The YTG believes that these concerns, if addressed, will ensure an effective development and benefits for the people of the Yukon.

Ethel Blondin, M.P. Western Arctic

Ms. Blondin supported the export applications. She was concerned, however, that Canadian requirements for gas should not be threatened by the approval of these export licences. In her view, the Northern Accord and the Dene/Metis land claim are important outstanding issues which should be settled, but should not be preconditions to the issuance of export licences.

Ms. Blondin thought that the development of the Mackenzie Delta/Beaufort Sea hydrocarbons would generate jobs for Northern people.

She stated that on-going training for Northerners must start now and that industry should provide employment at every level that is in accordance with the needs and special way of life of Northerners.

Tom Butters, M.L.A. Inuvik

Mr. Butters, a member of the Legislative Assembly of the NWT, appeared on his own behalf. He supported continued resource development in the Mackenzie Delta/Beaufort Sea area. However, he felt that some conditions should be applied to maximize economic opportunities for Northern residents and to minimize adverse environmental and social impacts.

He stated that a preference should be given to Northerners for training and employment. The Applicants should provide assistance to local businesses so they are aware of, and prepared for, contract opportunities. He suggested that the DIZ Society be involved in the review of socio-economic matters to ensure that local benefits are maximized.

Mr. Butters was also concerned about the environment. He recommended that the Environmental Screening and Impact Assessment Board and the Department of Energy, Mines and Petroleum Resources play an important role in evaluating and managing environmental impacts. With this involvement, Northerners would be assured that the developments will be sensitive to local concerns.

Mr. Butters stated that a Mackenzie Valley route would be the most efficient option. He believed that it could lead to improved transportation infrastructure in the North.

Jonathan Churcher

Jonathan Churcher, a citizen of Inuvik, advanced an innovative idea to the Board related to his environmental concerns. He suggested that the Board weigh criteria related to the Applicants' historical environmental performance and future financial and policy commitments to global alternative energy research and development in all its export licence and pipeline certificate decisions.

Porcupine Caribou Management Board

The Porcupine Caribou Management Board had concerns regarding any development projects on lands utilized by the caribou herd including the calving grounds and the migration routes.

Inuvik Native Band

The Inuvik Native Band said that many people among Native groups supported the export applications because they believed that there was going to be a pipeline built now.

The Band believes that the project should go ahead but that companies should recognize the need for co-operation with its people both in terms of routing and economic benefits because the pipeline would be built on their land. The Chief of the Band said that his people are interested in getting jobs with the oil companies.

Old Crow Indian Band

The Vuntut Gwitchin Band Council of Old Crow expressed concerns with respect to the export licences under consideration. The principal concerns expressed were related to the pipeline routing. They fear that these applications might result in a big push to connect Alaskan gas across the Yukon North Slope and emphasized that there should be no construction on the Yukon North Slope nor along the Dempster. According to the Band, different pipeline routes must be considered by the NEB in order to evaluate the benefits to the Band. It will support a Mackenzie Valley pipeline if land claims are settled and if there is participation by the Dene/Metis in business and employment opportunities.

Views of the Board

The Board believes that if the export project is to provide maximum benefits to the North and its people, there is a fundamental need for a good working relationship and understanding between the people of the North and the Applicants.

Furthermore, the Board not only agrees with the necessity for early planning in terms of establishing training programs and identifying business opportunities and infrastructure requirements, but it also considers this essential. The Board encourages the Applicants to work with government agencies, communities and associations, like the DIZ Society, at an early stage in the project to ensure that everyone involved is well informed during the development process and as a result is able to optimize their participation. The Board considers that a manpower training and employment program should be developed in an integrated fashion reflecting the overall development activities in the North. The Board concludes that it would not be appropriate to include a condition, in any export licence which might be issued, that would require the Applicants to provide training programs and employment.

The Board recognizes that there will be some impacts on northern infrastructure associated with development and production of hydrocarbons. Some of these impacts are quantifiable; some others are not. As discussed in Chapter 7, the Board has satisfied itself that the project's net benefits are sufficiently large to cover all these costs. However, the Board does not have the power to determine who will pay these costs. That power resides with other government agencies.

Various parties expressed concerns related to the route for the pipeline and the potential environmental impacts associated with the construction and operation of the pipeline. Details of pipeline routing and environmental impacts are matters which would be fully addressed in a hearing under Part III of the NEB Act before any pipeline were constructed.

Other Issues

The Council of Canadians

In its written submission to the Board, the Council of Canadians reached five conclusions concerning the licensing of exports of Delta gas:

- First, that there is "no pressing need for the application(s) to be approved at this time. (They) should therefore be denied because (they) threaten long-term Canadian energy security and our future industrial development."

- Second, it concluded that "the free trade agreement does not preclude restraints on energy exports provided the established proportion of Canadian production going to exports is maintained. The NEB Act does not bar the Board from managing new export licenses such that this proportion is kept at an acceptably low level".

- Third, the Council of Canadians recommended that "any future applications should only be considered at a time when all long-term economic aspects have been fully considered, as well as the environmental and social impacts of development, and the interests of northern communities".

- The Council's last two conclusions related to its recommendation that exports be restricted to no more than 40 percent of Canadian production, namely: "Restraint should now be placed upon export licence(s) from conventional reserves to ensure that the proportion of Canadian gas production sold in the United States does not exceed 40%" and:

- "Any future licence granted with respect to frontier reserves (such as the Mackenzie Delta, the Beaufort Sea, the Arctic Islands, or the Atlantic offshore fields) should specify that exports shall not exceed 40% of production, in order to ensure that Canada's future energy needs will be met even in emergency circumstances".

The Council of Canadians expressed concern that granting the licences would lead to an increase in the proportion of Canadian gas production delivered to the export market which, in the event of a supply emergency under the Free Trade Agreement, would lead to an onerous obligation to supply gas to the U.S. market, at a time when Canadians might be in need of secure energy supplies.

It submitted that Canadian natural gas demand projections were likely underestimated and stated that if demand were higher than that projected by the Board staff in the September 1988 Report, exports would have to be reduced and new gas reserves developed to meet this demand, relative to the export and reserves levels shown in that report. The Council of Canadians provided this as an example, rather than an actual forecast.

The Council of Canadians noted that while the Canadian gas supply situation is "much better" than the gas supply outlook for the United States, it is concerned that the depletion of Canadian discovered reserves has been high and that the rate of discovery of new gas reserves in conventional areas in Canada shows a continuing long-term declining trend.

Based on these observations about Canadian gas supply and demand, the Council of Canadians concluded that while they "do not believe that Canada is facing an immediate natural gas supply crisis ... the end result of all these (export) projects will inevitably make it harder and more expensive for Canadians to use their own natural gas".

With respect to the timing of the development of Arctic gas resources, the Council of Canadians was not against development or export of such

resources, provided that exports were restricted to 40 percent of production and long-term economic, social and environmental impacts were fully considered. The Council of Canadians stated that the present deregulated approach to energy exports and the Free Trade Agreement have caused the Applicants to apply for export licences at this time, since Canadian energy policy may change at a future date, implying a less favourable environment for new exports.

Views of the Board

The Board notes that the Council of Canadians did not produce evidence to show that a threat to Canada's energy security would, in fact, arise from licensing the export of Delta gas.

The Board has assessed the Applicant's EIA and has accepted their conclusion that the export of the proposed volumes would not likely cause Canadians difficulty in meeting their energy requirements. The Board evaluates Canadian energy supply and demand on an on-going basis, and could advise the government if it anticipated circumstances in which trade restrictions would be warranted.

While the Board recognizes the Council of Canadians' concerns over the impact of the development of Delta gas on the environment and social structure of the North, it points out that the applications under consideration are solely for licences to export natural gas and not for the approval of pipeline facilities. Northern issues, such as the importance of resolving native land claims and social and environmental issues associated with the construction of a natural gas pipeline in the North, are more fully addressed in Chapter 8 where similar arguments, raised by the Dene/Metis and other northern residents, are discussed.

While the Council of Canadians implied that restricting exports to 40 percent of production would remove or lessen the threat to security of supply, it provided no evidence or argument supporting the choice of 40 percent as the appropriate level for restriction. It did not demonstrate in its evidence any particular relationship between the level of Canadian requirements for natural gas, domestic security of energy supply and a restriction of exports to 40 percent of production. The Board is also of the view that a restriction now, at the level suggested, could well delay delivery of Mackenzie Delta gas to Southern Canada and would not be in the public interest.

Chapter 10

Disposition

Section 118 of the Act requires that the Board, in considering an application for a licence to export gas, have regard to all considerations which it deems relevant. Section 118 of the Act also requires that the Board license for export only those volumes of natural gas which do not exceed the surplus remaining after making due allowance for reasonably foreseeable Canadian requirements, taking into account trends in discovery.

The Board complies with the requirements of Section 118 of the Act by using its Market-Based Procedure. Under this procedure, the Board considers complaints by Canadian users taking into account current conditions in Canadian gas markets and the EIA. In its determination of the public interest, the Board also examines all other relevant factors including whether the proposed export is likely to result in net benefits to Canadians, the nature of the gas supply, and transportation and sales arrangements to ensure that the application represents a substantive commercial arrangement.

The evidence and argument of the Applicants and the intervenors on the applications as well as the views of the Board on the various factors relevant to the Board's decision have been discussed in detail in the previous chapters. What follows is a summary of the Board's key findings.

The Board's assessment of the gas supply available to support the applications is set out in Chapter 2. The Board believes that the Applicants' projected production rates can be achieved and that they have sufficient supply to meet their proposed export requirements.

With respect to markets, the Board concurs with the Applicants that access to the export market is essential to the development of the Mackenzie Delta reserves for an in-service date in the late 1990s. While export contracts with firm terms and conditions have not yet been entered into, the Applicants have signed Precedent Agreements with several potential U.S. buyers who have expressed an interest in purchasing a portion of the gas proposed for export. Those potential buyers are established importers of Canadian natural gas who are major participants in the United States gas market. The Board is satisfied that there is a reasonable expectation that U.S. buyers will have sufficient markets to accommodate the level of exports contemplated in the applications. To ensure that final export arrangements were consistent with the evidence submitted at the hearing, the Board would require, as a condition of any licence, that Board approval of any executed export contract be obtained before volumes associated with that contract could be exported.

Turning to the question of the complaints procedure, the Applicants and most parties to the hearing recognized that, in the absence of export contracts with specific terms and conditions, the complaints procedure, as established by the Board, cannot operate. The Applicants indicated that they would accept, as a condition of any licence that might be issued, a requirement to file executed export contracts with the Board for review by Canadian buyers to determine whether there was a basis for complaints. This proposal was examined at the hearing and no party raised any serious objection. The Board is satisfied that the objectives of the Board's complaint procedure could be met if any licence were to contain the conditions described in the section containing the Views of the Board in Chapter 5. These conditions relate to the requirement to keep potential Canadian buyers advised of the quantities of Delta gas available for sale and to provide them with an opportunity to purchase such gas on terms and conditions, including price, similar to those under which the gas would be exported. Export contracts would have to be filed with the Board for approval and an opportunity provided for interested parties to

complain. Parties would be expected to govern themselves according to the principles and procedures described in Chapter 5.

Regarding the EIA, while the Board does not necessarily support all aspects of the methodology applied by the Applicants to determine the impact of the export of Delta gas on natural gas prices, demand and supply, the Board agrees that the applied-for export volumes are not likely to cause Canadians difficulty in meeting their future energy requirements at fair market prices.

The Board's benefit-cost analyses indicate that the proposed exports would likely provide net benefits under most reasonable assumptions.

These export applications raised matters of public interest related specifically to the North, such as the Dene/Metis land claim, benefits to Northerners, and gas for Northerners.

The Dene/Metis requested that, to avoid prejudicing their land claim, any facilities application should be delayed until the claim is settled, either by denying these applications or by means of a condition to any licence. The Board recognizes the importance of resolving native land claims. The applications under consideration are, however, solely for licences to export natural gas from the Delta region, and not for the approval of pipeline facilities. On the basis of the evidence before it, the Board is not convinced that approval of gas export licences would prejudice the settlement of the Dene/Metis claim. An approval of export licences does not mean that consideration of a facilities application would follow shortly, thereby straining the resources of the Dene/Metis. Considerable preparatory work, including detailed discussions with all Northerners, would be required before an application. Having weighed all relevant factors, the Board is of the view that a delay of the decision or a licence condition, as requested, would not be necessary or desirable.

On the question of benefits to Northerners, the Board is of the opinion that proper planning should occur to ensure that Northerners are in a position to take full advantage of available benefits. The Board encourages the Applicants to work with government agencies, communities and associations, like the DIZ Society, at an early stage in the project to ensure that everyone involved is well informed during the development process and as a result is able to optimize their participation. The Board considers that a manpower training and employment program should be developed in an integrated fashion reflecting the overall development activities in the North. The Board concludes that it would not be appropriate to include a condition in any export licence that would require the Applicants to provide training programs and employment.

In respect to the availability of gas for Northerners, the Board concludes that it would be difficult to include in any licence which might be issued a meaningful condition requiring the Applicants to supply natural gas to Northern residents because neither the routing of a pipeline nor the volumes of gas which might be required to supply Northern markets are known. In addition, such a condition is not necessary because of the Applicants' stated undertakings to provide gas to Northerners. The Board expects such undertakings to be fulfilled.

Based on the foregoing, the Board is satisfied that the requirements of Section 118 have been met and, accordingly, has decided to issue licences for the requested volumes and term. Governor in Council approval of the licences is required before this decision comes into effect. Appendix I contains the terms and conditions of the proposed licences.

J.R. Jenkins
Presiding Member

J.-G. Fredette
Member

D.B. Smith
Member

Terms and conditions of the licence to be issued to Esso Resources Canada Limited

1. The term of this licence shall be for the period commencing 1 November 1996 and ending on 31 October 2000, provided that if exports have commenced by 31 October 2000, the term shall extend for a period of twenty years from 1 November of the year in which such exports commenced.

2. The quantity of gas that may be exported under the authority of this licence shall not exceed 144 10^9m^3 during the term of this licence.

3. The licensee shall advise potential Canadian buyers who have declared an interest in buying gas from the Mackenzie Delta region of the quantities available for sale from time to time, and concurrently with negotiating export contracts, shall give such potential Canadian buyers an opportunity to purchase gas from the Mackenzie Delta region on terms and conditions, including price, similar to those under which the gas would be exported, provided that such Canadian buyers demonstrate an intention to buy such gas within a reasonable time after being so advised.

4. The licensee shall file with the Board executed contracts for the sale of gas associated with the export and shall not export gas related to any contract until such contract has been approved by the Board.

5. When contracts for the sale of gas associated with the export are filed with the Board, the licensee shall advise all parties to the hearing of the filing of such contracts and shall undertake such other notification with respect to the filing as the Board may deem appropriate. Interested parties will have sixty days from the date of filing of the export contracts with the Board, or such other time as the Board may authorize, to register complaints that they have not been afforded an opportunity to purchase gas on terms and conditions, including price, similar to those under which the gas would be exported.

6. The gas exported under the authority of this licence shall be gas produced in the Mackenzie Delta region described in the licensee's application.

Terms and conditions of the licence to be issued to Shell Canada Limited

The terms and conditions of the licence to be issued to Shell Canada Resources Limited are the same as the terms and conditions of the licence issued to Esso with the exception of Condition 2, which shall read as follows:

2. The quantity of gas that may be exported under the authority of this licence shall not exceed 25 10^9m^3 during the term of this licence.

Terms and conditions of the licence to be issued to Gulf Canada Resources Limited

The terms and conditions of the licence to be issued to Gulf Canada Resources Limited are the same as the terms and conditions of the licence issued to Esso with the exception of Condition 2, which shall read as follows:

2. The quantity of gas that may be exported under the authority of this licence shall not exceed 91 10^9m^3 during the term of this licence.

Appendix Table A-1

Comparison of Estimates of Esso's Productive Capacity

Millions of Cubic Metres (Bcf)

Year	Esso[1]		NEB	
1997	7 198	(254)	7 198	(254)
1998	7 198	(254)	7 198	(254)
1999	7 198	(254)	7 198	(254)
2000	7 198	(254)	7 198	(254)
2001	7 198	(254)	7 198	(254)
2002	7 198	(254)	6 992	(247)
2003	7 198	(254)	6 164	(218)
2004	7 198	(254)	6 994	(247)
2005	7 198	(254)	7 198	(254)
2006	7 198	(254)	7 198	(254)
2007	7 198	(254)	7 198	(254)
2008	7 198	(254)	7 198	(254)
2009	7 198	(254)	7 198	(254)
2010	7 198	(254)	7 198	(254)
2011	7 198	(254)	7 198	(254)
2012	7 198	(254)	7 198	(254)
2013	6 088	(215)	7 159	(253)
2014	4 840	(171)	6 548	(231)
2015	4 157	(147)	4 736	(167)
2016	3 522	(124)	2 945	(104)

1 Includes processing and pipeline fuel and losses.

Appendix Table A-2

Comparison of Estimates of Gulf's Productive Capacity

Millions of Cubic Metres (Bcf)

Year	Gulf[1]		NEB	
1997	4 120	(145)	4 120	(145)
1998	4 120	(145)	4 120	(145)
1999	4 120	(145)	4 032	(142)
2000	4 120	(145)	3 638	(128)
2001	4 120	(145)	3 290	(116)
2002	4 120	(145)	2 980	(105)
2003	4 120	(145)	2 699	(95)
2004	4 120	(145)	4 120	(145)
2005	4 120	(145)	4 120	(145)
2006	4 120	(145)	3 992	(141)
2007	4 120	(145)	3 740	(132)
2008	4 120	(145)	3 454	(122)
2009	4 120	(145)	3 208	(113)
2010	4 120	(145)	2 977	(105)
2011	4 120	(145)	4 120	(145)
2012	4 120	(145)	3 866	(136)
2013	4 120	(145)	3 332	(118)
2014	4 120	(145)	2 662	(94)
2015	4 120	(145)	2 226	(79)
2016	4 120	(145)	2 064	(73)

1 Plant gate sales gas.

Appendix Table A-3

Comparison of Estimates of Shell's Productive Capacity

Millions of Cubic Metres (Bcf)

Year	Shell[1]		NEB[2]	
1997	1 301	(46)	1 301	(46)
1998	1 301	(46)	1 289	(46)
1999	1 301	(46)	1 255	(44)
2000	1 301	(46)	1 249	(44)
2001	1 301	(46)	1 178	(42)
2002	1 301	(46)	1 090	(38)
2003	1 301	(46)	1 013	(36)
2004	1 301	(46)	947	(33)
2005	1 301	(46)	881	(31)
2006	1 301	(46)	827	(29)
2007	1 301	(46)	779	(27)
2008	1 301	(46)	735	(26)
2009	1 301	(46)	688	(24)
2010	1 239	(44)	841	(30)
2011	1 126	(40)	740	(26)
2012	1 033	(36)	673	(24)
2013	929	(33)	623	(22)
2014	847	(30)	582	(21)
2015	775	(27)	543	(19)
2016	713	(25)	510	(18)

1 Shell's forecast Niglintgak only.
2 NEB forecast includes Kumak.